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FIELD TESTING: APPLICATION OF COMBUSTION MODIFICATIONS TO CONTROL NOx EMISSIONS FROM UTILITY BOILERS

A. R. Crawford, et al

Exxon Research and Engineering Company

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16. ABSTRACT
The report describes field studies on utility boilers to develop NOx and other pollutant control technology by modifying combustion operating conditions. Tests were made on 12 pulverized-coal-fired boilers, including wall, tangentially, and turbo-furnace fired units representative of utility boiler manufacturers' current design practices. Six oil-fired boilers, converted from coal-firing, were also tested with combustion modifications for NOx control. Particulate emissions and accelerated furnace corrosion rates were also determined in some cases for coal-fired boilers. The tests consisted of three phases: short-term runs to define the optimum low NOx conditions within the constraints imposed by boiler operability and safety; boiler operation for 2 days (under low NOx conditions defined in the first phase) to check operability on a sustained basis; and operation of several boilers under baseline and low NOx conditions for about 300 hours (with air-cooled carbon steel corrosion coupons exposed near the furnace water walls) to obtain relative corrosion tendencies at accelerated rates. Analysis indicated that combustion modifications, chiefly low excess air firing coupled with staged burner patterns, can reduce NOx emissions from the tested coal-fired boilers by 25-60%, depending on the unit and its flexibility. NOx emissions were successfully correlated for normal and modified firing conditions with the percent stoichiometric air supplied to the burners.

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by

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SUMMARY

Exxon Research and Engineering Company has been conducting field studies on utility boilers under EPA sponsorship to develop NO_x and other pollutant control technology through the modification of combustion operating conditions. Under the present contract on this problem, Exxon's mobile sampling-analytical system has been used to test 12 pulverized coal-fired boilers of cooperating electric utilities. These boilers, including wall, tangentially, and turbo-furnace fired units, had been recommended by the utility boiler manufacturers as being representative of their current design practices. Also, combustion modifications for NO_x control were tested for six oil-fired boilers which had been converted from coal firing service.

In addition to gaseous emission measurements, particulate emissions and accelerated furnace corrosion rates also have been determined in a number of cases for coal-fired boilers. The test design used consisted of three phases. First, statistically designed short-term runs were made, to define the optimum "low NO_x" conditions within the constraints imposed by boiler operability and safety, slagging, unburned combustible emissions and other undesirable side effects. Second, the boilers were usually operated for about two days under the "low NO_x" conditions defined in the first phase, to check operability on a sustained basis. Third, several boilers were operated under both baseline and "low NO_x" conditions for about 300 hours, with carbon steel corrosion coupons mounted on air-cooled probes exposed near the water walls of the furnaces, to obtain relative corrosion tendencies at accelerated rates.

Analysis of the gaseous emission data obtained shows that combustion operating modifications, chiefly low excess air firing coupled with staged burner patterns, can reduce NO_x emissions from the coal fired boilers tested by 25 to 60%, depending on the unit and its flexibility for modifications. The NO_x emissions measured have been successfully correlated for both normal and modified firing conditions with the percent stoichiometric air supplied to the burners.

For dry particulate mass loadings, the differences observed under baseline and "low NO_x" operating conditions have been found to be relatively minor. However, unburned carbon in the fly-ash seems to increase for "low NO_x" firing in front wall and horizontally opposed fired boilers, and to decrease for tangentially fired units. The potential debits in overall performance based on these limited data for front wall and horizontally opposed fired boilers have been shown to be offset by improved efficiencies realized through lower excess air operation in "low NO_x" firing.

Boiler efficiency calculations comparing baseline and modified "low NO_x" operations indicate essentially no efficiency penalty for the implementation of combustion modifications to control NO_x emissions.

Significantly, the accelerated corrosion tests have not revealed major differences in corrosion rates measured under normal and staged firing operating conditions. More tests and long term runs, with particular emphasis on corrosion and slagging problems, are needed to demonstrate the promising leads uncovered in this study.

1. INTRODUCTION

In continuing studies sponsored by EPA, Exxon Research and Engineering Company (Exxon) is involved in the development of nitrogen oxides (NO_x) emission control techniques for stationary sources. Our "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources" (1-3) characterized the nature and magnitude of the stationary NO_x emission problem, assessed existing and potential control technology based on technical feasibility and cost-effectiveness, developed a first-generation model of NO_x formation in combustion processes, and prepared a set of comprehensive 5-year R&D plan recommendations for the Government with priority rankings.

Fossil fuel fired electric utility boilers were identified by the above study as the largest single stationary NO_x emission sector, responsible for about 40% of all stationary NO_x. Consequently, as part of Phase II of our "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources", Exxon conducted a systematic field study of NO_x control methods for utility boilers (4-6). The objectives of this field study were to determine new or improved NO_x emission factors according to fossil fuel type and boiler design type, and to explore the application of combustion modification techniques to control NO_x emissions from such installations.

Exxon provided a specially designed mobile sampling-analytical van for the above field testing. This van was equipped with gas sample, thermocouple, and velocity probes, with associated sample treating equipment, and continuous monitoring instrumentation for measuring NO, NO_2, CO, CO_2, O_2, SO_2, and hydrocarbons.

Gas, oil, and coal fired utility boilers representative of the U.S. boiler population were tested. Combustion modifications were implemented in cooperation with utility owner-operators (and with major boiler manufacturer subcontractors for three of the coal fired boilers tested), and emission data were obtained in a statistically designed field program. The 17 boilers (25 boiler-fuel combinations) tested included wall-fired, tangentially-fired, cyclone-fired, and vertically-fired units ranging in size between 66 and 820 MW generating capacity.

Major combustion operating parameters investigated consisted of the variation of gross boiler load, excess air level, staged firing patterns, flue gas recirculation, burner tilt, primary/secondary air ratio, and air preheat temperature. Operation under reduced load conditions reduced the NO_x emissions, but only for gas firing was the percent NO_x reduction greater than the percent load reduction. Base-line emissions were correlated in a statistically significant manner with the MW generated per "equivalent" furnace firing wall. In general, unburned combustible emissions, i.e., CO and hydrocarbons were found to be negligibly small under base-line conditions, and acceptably low even with NO_x control combustion modifications. The NO_2 portion of the flue gas was always five percent or less of the total NO_x emitted.

The effectiveness of combustion modifications was found to vary with individual boiler characteristics for each fuel. For gas fired boilers, NO_x emissions could be reduced on the average by about 60% at full load. even though in large, gas fired boilers limited by heat transfer surface, NO_x emission levels as high as 1000 ppm prevailed in the absence of combustion modifications. Uncontrolled emissions from fuel-oil fired boilers averaged lower values than for gas firing, but combustion modifications could be less readily implemented. With coal firing, only two of the seven boilers tested (one a tangential unit, the other a front wall fired boiler) could be operated in a manner conducive to reducing NOx emissions. This operation consisted of firing the operating burners in the lower burner rows or levels with substoichiometric quantities of air, and supplying the additional air required for the burn-out of combustibles (keeping overall excess air as low as possible) through the air registers of the uppermost row or level. In these short-term, exploratory tests, NO_x emissions were reduced by over 50% compared with the standard firing mode. In one set of boiler tests, this was demonstrated to be possible without decreasing thermal efficiency or increasing the amount of unburned carbon in the fly-ash. Due to stopping the pulverizer mill supplying coal to the top level of burners, the amount of fuel that could be fired was reduced, resulting in a decrease of about 15% from maximum rated capacity. The NO_x reductions achieved were not affected by this reduction in load, as normal and modified combustion operations were compared at the same boiler load.

While the exploratory data obtained in the above study on controlling NO_x and other pollutant emissions from utility boilers by combustion modifications showed good potential, a number of critical questions had remained to be answered. Thus, for coal fired utility boilers, potential problems of slagging, corrosion, flame instability and impingement, increased carbon in the fly-ash, the actual particulate loadings and potential decreases in boiler efficiency which could result from the modified combustion operations still needed to be assessed in sustained test runs.

The purpose of Exxon's present field testing program, sponsored by EPA under Contract No. 68-02-0227, has been to obtain more detailed information primarily on the application of combustion modification technqiues to coal fired utility boilers, in cooperative efforts with boiler operators and manufacturers coordinated by EPA. U.S. utility boiler manufacturers (Babcock and Wilcox, Combustion Engineering, Foster Wheeler, and Riley-Stoker) have recommended boilers characteristic of their current design practices. They have provided their help in making arrangements for testing with the cooperating boiler owner/operators, and in a number of cases assigned representatives to participate in Exxon's field tests.

In addition to the continuous monitoring instrumentation described above, four EPA-type particulate sampling trains have been added to Exxon's system. These trains and other equipment have been transported to the testing sites in an auxiliary van.

The approach used for field testing coal-fired boilers in this study has been first, to define the optimum operating conditions for NO_x emission control without apparent unfavorable side effects, in short-term, statistically design test programs. Second, the boiler was operated for 1-3 days under the "low NO_x" conditions determined during the optimization phase, for assessing boiler operability problems. Finally, where possible, sustained 300-hour runs were made under both baseline and modified combustion ("low NO_x") operating conditions. During this period, air-cooled carbon steel coupons mounted on corrosion probes were exposed in the vicinity of furnace water tubes, to determine through accelerated corrosion tests whether operating the boiler under the reducing conditions associated with staged firing results in increased fire-side water tube corrosion rates. Particulate samples were obtained under both baseline and "low NO_x" conditions, and engineering information on boiler operability, e.g., on slagging problems, and on boiler performance were also obtained. For the coal-to-oil converted boilers tested, gaseous emission measurements were made in the same manner as for the coal-fired units.

2. OVERALL CORRELATIONS AND CONCLUSIONS

This section of the report presents the overall correlations and conclusions based on the results obtained in a field program conducted on twelve representative coal-fired utility boilers. Also, our conclusions on the results of six boilers converted from coal to oil service are presented. Because of the emphasis in this study on the control of NO_x emissions by combustion modifications, the gaseous emission measurements obtained without adverse side-effects during short-term optimization runs are analyzed in depth in the section that follows.

Baseline NO_x emissions from the boilers tested under normal operating conditions, usually at full rated boiler capacity, have been successfully correlated with excess air (or percent stoichiometric air to the active burners) and boiler load. Also, the percent reduction from baseline levels in NO_x emissions resulting from the application of staged firing has been correlated with the percent stoichiometric air supplied to the active burners.

Particulate measurements have been made under both baseline and modified combustion ("low NO_x") conditions for several of the boilers tested. The objective was to assess the relative changes in total flue gas particulate loadings and in the unburned carbon content of the flyash that may be due to the application of combustion modification techniques, chiefly staged firing of burners with low overall levels of excess air. No major differences in particulate loadings have been found, but the unburned carbon content of flyash appears to be somewhat affected by combustion modifications.

In a similar manner, the potential of increased furnace water-tube corrosion rates resulting from reducing conditions created by sub-stoichiometric air supply to the burners has been explored. For this purpose, accelerated corrosion tests have been made under both baseline and modified combustion conditions for 300-hour sustained periods. The objective of these corrosion probing studies was to establish whether the application of staged firing with low overall excess air supply could cause severe corrosion problems in the furnace. As will be discussed further, comparison of the corrosion rates measured under baseline and modified firing conditions indicates that the reducing environment in the furnace does not appear to cause severe corrosion problems.

The overall correlations and conclusions discussed in this section will be followed by subsequent sections of this report containing our recommendations for boiler operators and manufacturers on NO_x emission control, details of the field tests, results on each individual boiler tested, and recommendations on future emission field studies.

2.1 NO_x Emissions for Coal Fired Boilers

In this section the results obtained for all coal-fired boilers tested will be analyzed. Individual boiler test data are summarized in Section 6 of this report and further details on gaseous emissions are presented in Appendix A. Typical boiler cross-sectional diagrams for wall, tangential, and turbo-furnace fired boilers are shown in Appendix C.

The design and operating features of the twelve coal-fired boilers tested are summarized in Table 2-1, listed in the sequence of the individual tests. Of the twelve boilers, seven were wall fired units (four front wall and three horizontally opposed fired units, ranging in size from 100 MW to 800 MW), four were tangentially fired, ranging in size from 250 MW to 350 MW) and one was a turbo-furnace boiler (with maximum rated design capacity of 450 MW, but tested only at 370 MW). These boilers are representative of current design practices, and have been selected for field studies at the recommendation of their respective manufacturers as discussed in Section 4.1.

Tables 2-2, 2-3, and 2-4 summarize the NO_x emission levels measured from single wall-fired, horizontally opposed wall-fired, and tangentially-fired (plus a turbo-furnace) boilers, respectively. "Low NO_x" operation at essentially full load reduced NO_x emission reductions of 55 to 64% compared to full load, baseline emission levels.

Comparison of the NO_x emission data in Table 2-4 with those in Tables 2-2 and 2-3 reveals that baseline NO_x emission levels from tangentially fired boilers are lower than those from wall fired boilers. (The turbo-furnace boiler was tested at 370 MW, due to operating problems at the time of our test, compared with design full load of 450 MW, and hence, additional testing is needed to measure baseline, full load NO_x emission levels.) Combustion modifications for "low NO_x" staged firing operation with 15-20% load reduction enabled these tangentially fired boilers to further decrease NO_x emissions. "Low NO_x" operation with further load reduction resulted in NO_x reductions of 55 to 64% compared to full load, baseline emission levels.

As will be discussed in Section 6 of this report, it should be recognized that these results were obtained during short-term test periods and that long-term testing is needed to study slagging, corrosion and other operating conditions. It is expected that slagging problems in some boilers can be largely overcome by increasing slag blower steam pressures, increasing the use of slag blowers and perhaps the addition of slag blowers at troublesome locations. Lower NO_x emissions would also be expected in many boilers from improved furnace maintenance, so that air-to-fuel ratios are as uniform as practical across the furnace. Research at extremely low levels of stoichiometric air to the active burners (less than 75%) with staged firing may yield significantly improved NO_x emission levels with decreased slagging, because of lower temperatures. Also, the addition of secondary air-ports (frequently termed "NO-ports" or "overfired air-ports") would probably allow most boilers to reduce NO_x emissions significantly during full-load operation with all burners firing coal.

TABLE 2-1

SUMMARY OF COAL FIRED BOILERS TESTED

Boiler Operator	Station and Boiler No.	Boiler Mfr.[a]	Type of Firing[b]	MCR (MW)	No. of Burners	Test Variables	No. of Test Runs
Tennessee Valley Authority	Widows Creek 6[c]	B&W	FW	125	16	4	41
Gulf Power	Crist 6[c]	F-W	FW	320	16	4	22
Georgia Power	Harllee Branch 3[c][d]	B&W	HO	480	40	4	51
Arizona Public Service	Four Corners 4[c][d]	B&W	HO	800	54	5	26
Utah Power and Light	Naughton 3[c][d]	CE	T	330	20	6	26
Alabama Power	Barry 4[c][d]	CE	T	350	20	7	46
Alabama Power	Barry 3	CE	T	250	48	4	8
Tampa Electric	Big Bend 2	RS	Turbo	350	24	4	14
Central Illinois Light	E.D. Edwards 2	RS	FW	256	16	4	19
Basin Electric	Leland Olds 1	B&W	HO	218	20	3	13
Pacific Power and Light	Dave Johnston 2	B&W	FW	105	18	3	14
Pacific Power and Light	Dave Johnston 4	RS	T	348	28	7	6
							236

(a) B&W - Babcock and Wilcox
CE - Combustion Engineering
F-W - Foster Wheeler
RS - Riley Stoker

(b) FW - Front Wall
HO - Horizontally Opposed
T - Tangential
Turbo - Turbo-Furnace

(c) Particulate tests performed on these boilers.

(d) Corrosion probe tests performed on these units.

TABLE 2-2

SUMMARY OF NO_x EMISSIONS FOR FRONT WALL FIRED BOILERS

(COAL FIRING)

Boiler	Operating Mode (Gross Load - MW)	$\%O_2$	NO_x Emissions ppm $(3\%\ O_2)$	NO_x Emissions Lb./10^6 BTU *	NO_x Emissions gm./10^6 Cal *	ppm CO $(3\%\ O_2)$
Dave Johnston No. 2	Baseline (101)	5.0	454	0.60	1.08	112
	"Low NO_x I" (99)	5.2	214	0.28	0.50	962
Widows Creek No. 6	Baseline (125)	3.4	634	0.84	1.51	258
	"Low NO_x I" (123)	2.0	379	0.50	1.90	665
	"Low NO_x II" (100)	2.7	295	0.39	0.70	818
E. D. Edwards No. 2	Baseline (253)	3.5	703	0.93	1.67	42
	"Low NO_x I" (256)	1.6	359	0.48	0.86	172
	"Low NO_x II" (221)	3.0	295	0.39	0.70	26
Crist No. 6	Baseline (350)	3.3	832	1.11	2.00	22
	"Low NO_x I" (320)	2.2	550	0.73	1.31	196
	"Low NO_x II" (260)	3.5	526	0.70	1.26	217

---

* Calculated as NO_2

TABLE 2-3

SUMMARY OF NO_x EMISSIONS FOR OPPOSED WALL FIRED BOILERS

(COAL FIRING)

Boiler	Operating Mode (Gross Load - MW)	$\%O_2$	NO_x Emissions			ppm CO
			ppm ($3\%\ O_2$)	$\frac{Lb.}{10^6\ BTU}$ *	$\frac{gm.}{10^6\ Cal}$ *	($3\%\ O_2$)
Leland Olds No. 1	Baseline (219)	3.9	569	0.76	1.37	24
	"Low NO_x I" (218)	2.8	375	0.50	0.90	231
	"Low NO_x II" (185)	2.2	260	0.34	0.61	518
Harllee Branch No. 3	Baseline (490)	3.5	711	0.95	1.71	27
	"Low NO_x I" (473)	1.4	463	0.62	1.12	152
	"Low NO_x II" (400)	1.6	359	0.48	0.86	316
Four Corners No. 4	Baseline (800)	5.0	935	1.24	2.23	18
	"Low NO_x I" (794)	3.2	488	0.65	1.17	172
	"Low NO_x II" (600)	3.0	452	0.60	1.08	33

---

* Calculated as NO_2

TABLE 2-4

SUMMARY OF NO_x EMISSIONS FOR TANGENTIALLY FIRED BOILERS

(COAL FIRING)

Boiler	Operating Mode (Gross Load - MW)	%O_2	NO_x Emissions			ppm CO ($3\%\ O_2$)
			ppm ($3\%\ O_2$)	Lb./10^6 BTU *	Gm/10^6 Cal *	
Barry No. 3	Baseline (250)	3.1	410	0.55	0.99	61
	"Low NO_x I" (248)	1.3	310	0.41	0.74	100
Naughton No. 3	Baseline (334)	4.2	531	0.71	1.28	27
	"Low NO_x I" (310)	2.3	219	0.29	0.52	499
	"Low NO_x II" (256)	3.0	197	0.26	0.47	376
Barry No. 4	Baseline (350)	4.4	415	0.55	0.99	24
	"Low NO_x I" (300)	2.4	273	0.36	0.65	113
	"Low NO_x II" (186)	2.2	189	0.25	0.45	281
Dave Johnston No. 4	Baseline (306)	4.2	434	0.53	1.04	19
	"Low NO_x" (304)	3.3	384	0.51	0.92	99
TURBO - FURNACE BOILER						
Big Bend No. 2	Baseline (370)	2.8	600	0.80	1.44	28
	"Low NO_x I" (370)	1.4	398	0.53	0.95	319
	"Low NO_x II" (300)	1.8	341	0.45	0.81	87

---

* Calculated as NO_2

The ranges of NO_x emissions measured as a function of % stoichiometric air without staging during the short term optimization phases of the individual field test programs are presented graphically in Figure 2-1. In this figure, and in subsequent graphical presentations, the power generating stations and boilers are coded by the following letters (for clarity, the boiler numbers appear in these figures only for stations where more than one boiler was tested):

Code Letters		Station	Boiler No.
WC	6	Widows Creek	6
HB	3	Harllee Branch	3
FC	4	Four Corners	4
N	3	Naughton	3
B	3	Barry	3
B	4	Barry	4
BB	2	Big Bend	2
E	2	E. D. Edwards	2
O	1	Leland Olds	1
J	2	Dave Johnston	2
J	4	Dave Johnston	4
C	6	Crist	6

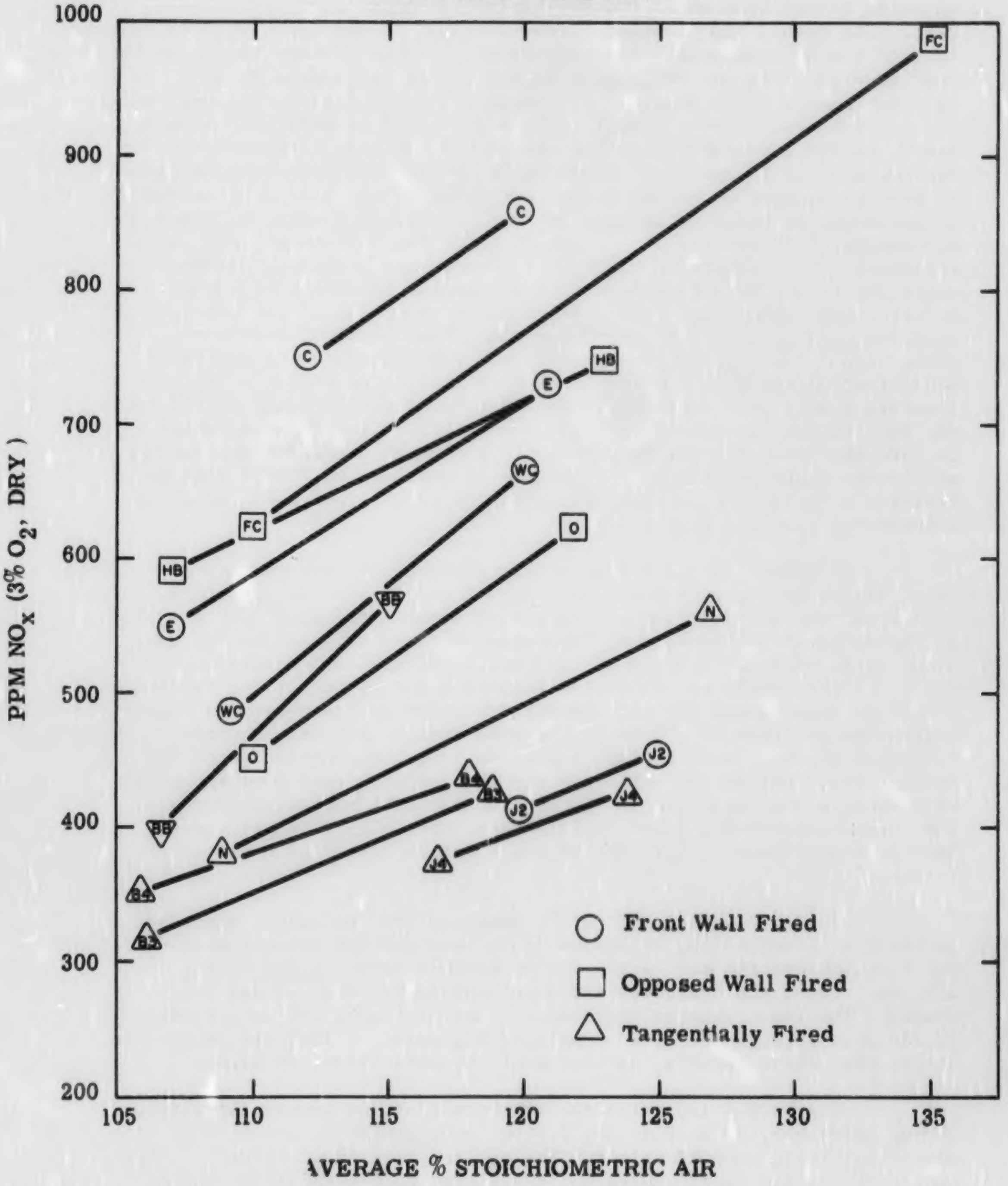
The absolute levels of NO_x emissions shown in Figure 2-1 are clearly related to the level of excess air (or % stoichiometric air) for each boiler tested. In fact, the slopes of the NO_x vs. % stoichiometric air lines exhibit a rather small variability, which is remarkable in view of the fact that the data have been obtained on different boiler and burner types and sizes, fired with different types of coal. The very strong dependence of NO_x emission levels on available oxygen will be discussed further.

As in our "Systematic Field Study", the uncontrolled baseline NO_x emissions have been correlated with the load generated per equivalent furnace firing wall. The earlier data (4) have been recalculated using the same set of assumptions as for the result of the study i.e., that the number of equivalent firing walls is 1, 2, and 4 for front wall, horizontally opposed, and tangentially fired boilers, respectively. For boilers having twin furnaces, this number has been doubled. However, in contrast to the earlier correlations (4), the above factor of 2 was not used to account for the presence of a division wall in the furnace, because the heat absorbing effect of a division wall is smaller than that of furnace side walls. Also, the data for two wet-bottom (one of them cyclone fired) boilers tested previously (4) have been omitted from the correlations, because of the uncharacteristically long residence time at high temperatures in these two units.

FIGURE 2-1

PPM NO_X VS % STOICHIOMETRIC AIR NORMAL FIRING

(COAL FIRED BOILERS)



As a first approximation, the above type of correlation takes into account the relationship of furnace heat release rate to the heat absorption rate. Figure 2-2 presents the correlation of baseline NO_x emission levels (ppm at 3% O_2, dry basis) vs. gross load per furnace firing wall. The dashed line labeled "Present Study" is the least squares regression of the 12 data points corresponding to the 12 boilers tested in the present program. The dotted line in Figure 2-2 is calculated from our "Systematic Field Study" (4), while the solid line is the regression for all boilers. There appears to be a very good correlation on this basis, as the correlation coefficient is 0.9, and the standard error on the estimate is 70 ppm NO_x. It should be noted that individual boilers of unusual furnace or burner design may produce emission rates outside of the expected range calculated for the relationship shown in Figure 2.2. Our sample of 12 boilers plus 5 out of 7 for the 1971 field study is a relatively small sample of the highly diverse populations of boilers operating in the United States. The regression intercept of 390 ppm NO_x at zero load corresponds to a conversion of about 20% of the average fuel nitrogen content of 1.3 wt. % of the coal types fired in this study. This observation is a strong indication of the significant contribution of bound fuel nitrogen to NO_x emissions from coal fired boilers. On an absolute scale, this contribution would account for over 50% of the total NO_x emitted for the majority of the coal-fired boilers tested, which is in agreement with laboratory results (7) on this problem. Substoichiometric air supply to the active burners is expected to reduce both the fixation of molecular N_2, and the oxidation of fuel nitrogen, based on independent laboratory data (8).

Figures 2-3 and 2-4 have been prepared to show the overall correlations of NO_x emissions vs overall % stoichiometric air and % stoichiometric air supplied to the active burners. Figure 2-3 is a plot of "normalized" NO_x emissions, expressed as the % of baseline NO_x emissions (full load and 20% excess air) vs. % overall stoichiometric air (or % stoichiometric air to active burners under normal firing conditions). The solid lines shown for each boiler are based on least-squares linear regression analysis of all test runs made uner normal (all burners firing coal), full load firing conditions. With the exception of the turbo-furnace boiler, all of these regressions show very good agreement with about a 20% reduction in NO_x at 110% vs. 120% stoichiometric air. The three tangentially fired boilers show especially good agreement in this significant correlation of NO_x emission levels with excess air levels.

Figure 2-4 is a plot of "normalized" NO_x emissions expressed as the % of baseline NO_x emissions (full load and 20% overall excess air) vs. % stoichiometric air to the active burners under staged firing conditions. Thus, the ordinates are identical in Figures 2-3 and 2-4. However, the least squares regression lines of Figure 2-4 do not necessairly pass through the 100% normalized NO_x point at 120% stoichiometric air to the active burners, as they must, by definition, in Figure 2-3.

Figure 2-4 indicates the importance of low excess air firing on NO_x emissions, as well as the further benefits of staged firing and additional firing modifications. The opposed wall fired boilers (Harllee Branch No. 3, and Four Corners No. 4 boilers) showed excellent agreement, as

FIGURE 2-2

UNCONTROLLED NO_x EMISSIONS VS
GROSS LOAD PER FURNACE FIRING WALL

(COAL FIRED BOILERS)

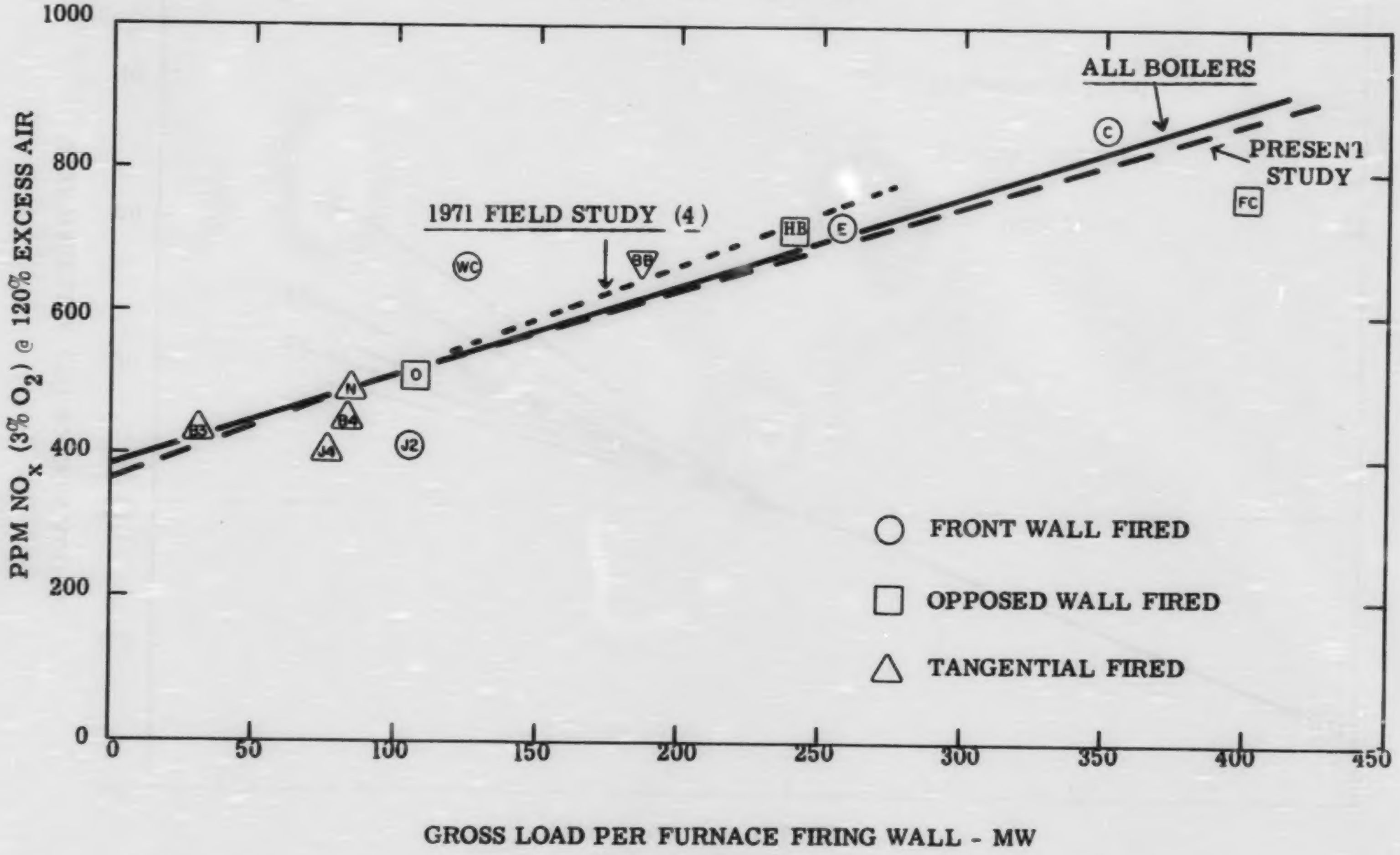


FIGURE 2-3

EFFECT OF EXCESS AIR ON NO_x EMISSIONS UNDER NORMAL OPERATION

(COAL FIRED BOILERS)

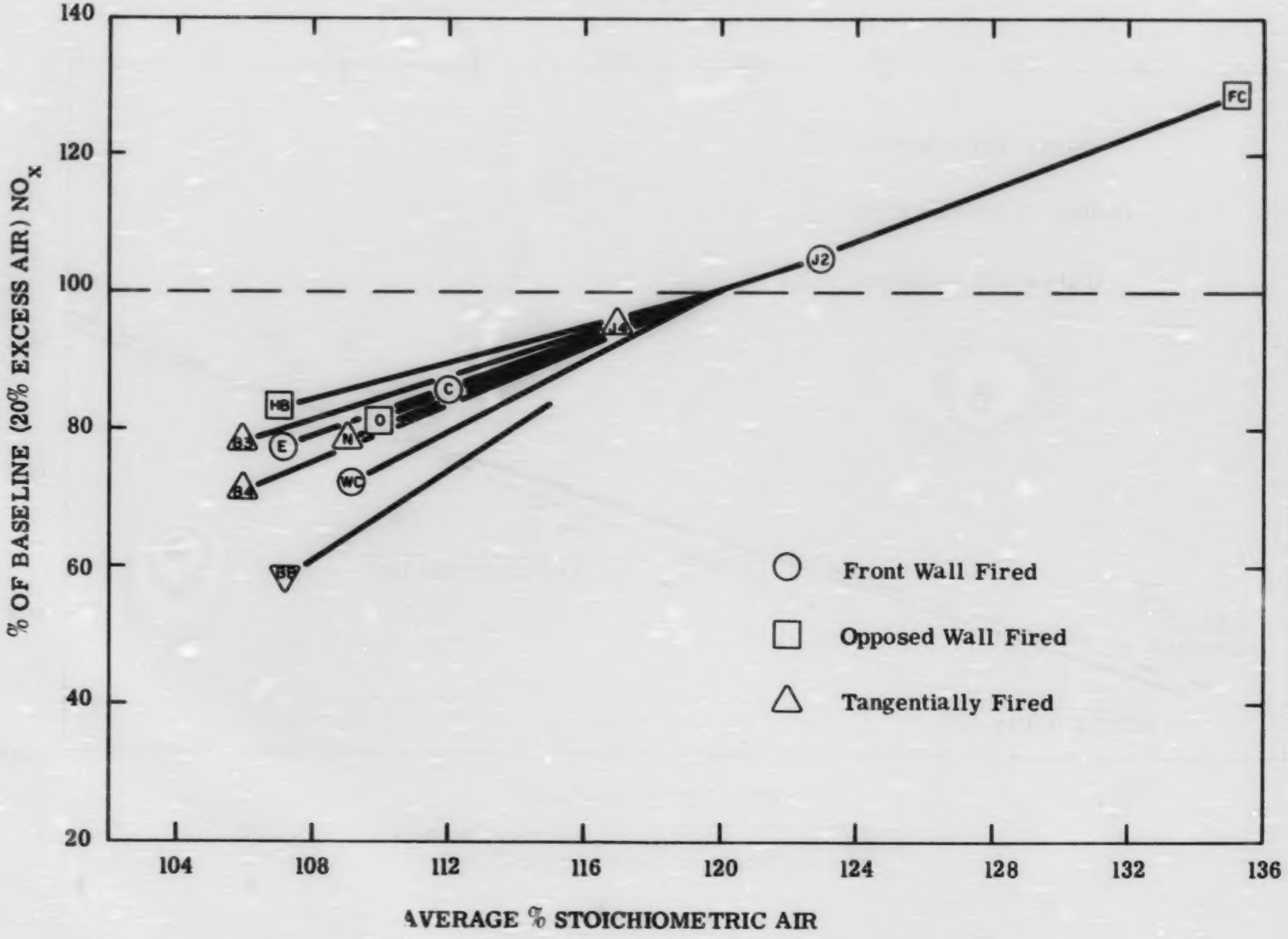
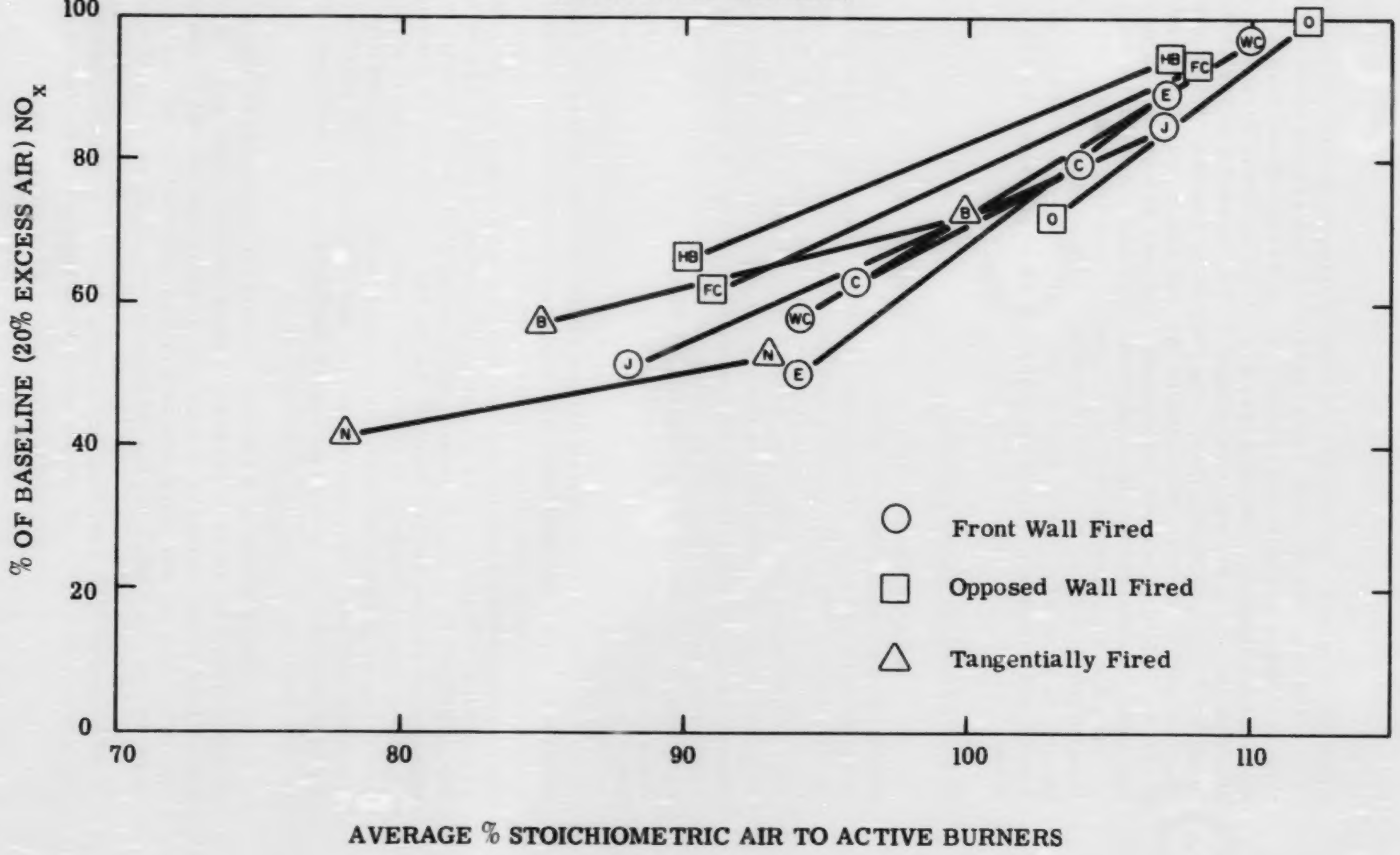


FIGURE 2-4

EFFECT OF EXCESS AIR ON NO_x EMISSIONS UNDER MODIFIED FIRING CONDITIONS

(COAL FIRED BOILERS)



would be expected, since both of them represent modern design practices of Babcock and Wilcox with their cell-type burners. Leland Olds No. 1 representing a somewhat different type of design shows more of a deviation from this behavior. The tangentially fired boilers, Barry No. 4 and Naughton No. 3, that employed staged firing showed similar trends, with Naughton No. 4 producing lower NO_x emissions because it was tested at lower % stoichiometric air levels. Of the front wall-fired units, Widows Creek No. 6 boiler showed consistently larger reductions in normalized NO_x under normal operating conditions than the other front wall fired units at the same % stoichiometric air levels. However, under modified firing conditions all front wall fired boilers gave similar results. Boiler parameters such as size, coal type fired, pulverizer conditions, and other design and operating variables undoubtedly contributed to the differences found.

2.2 Particulate Mass Loading

As described in detail in Section 4 of this report, four Research Appliance Company EPA-type particulate sampling trains were used in this program. The design of this equipment follows the guidelines of EPA Method No. 5 (9). Many difficulties occur in actual operation, as is inherent to particulate testing. Care must be taken to assure that the probes and test boxes are at specified temperatures. Even so, especially in cold weather, moisture in the flue gases condensing in the apparatus can quickly plug filters which results in aborting the test. Tests for leaks in each train prior to testing is also needed if meaningful data are to be obtained. Plugging of sampling probes on occasion also occurs, and can present difficulties in boilers with high particulate loadings.

The boilers tested proved to be another source of recurrent problems. Most boilers were not equipped with suitable testing facilities. Sample test ports are often located too close to bends in the flue ducts where particulate concentrations, due to centrifugal action, are strongly stratified. Interferences of the probes with supports inside the flue ducts and of the test apparatus with other obstructions near test locations outside the boiler contribute to the difficulty of running particulate loading tests. Last but not least, the EPA-type test train is built for horizontal probing, while most boiler test locations require vertical probing. Our equipment has been modified for vertical probing, so that usually the construction of scaffolding was necessary for access to the ducting.

Despite the problems of conducting particulate tests, the results obtained in this program, summarized in Table 6-17, are consistent and appear to be reliable within the limitations of this type of testing. The objective of our work was to develop information on potential "side effects" of "low NO_x" firing techniques on total particulate loadings and on the carbon content of the flyash produced. Although strict adherence to EPA recommended sampling procedures was not possible, due to the limited availability of sample port locations and interferences with building and boiler structures, the same procedures were used under both baseline and "low NO_x" conditions. Therefore, the differences observed in the results on particulate emissions and particulate carbon content are felt to be representative of the relative effects of combustion modifications on particulate emissions.

As expected, some side effects did develop under "low NO_x" firing conditions. Total quantities of particulates tend to increase but not significantly and the consequences appear to be relatively minor. This trend would have an adverse effect on the required collection efficiency of electrostatic precipitators to meet present Federal emission standards, but the increases required in precipitator efficiency appear to be quite small based on these limited tests.

Another potentially adverse side effect of "low NO_x" operation with staged firing is that of increased carbon content of flyash. The carbon content of the particulates with "low NO_x" operation, according to the results of the study, in some cases increased on front wall fired boilers by as much as from 6 to 10.5% on the average and from 5 to 8% on horizontally opposed fired boilers. However, the data are quite scattered, and these increases do not appear to be directly related to the change in emissions with "low NO_x" firing techniques, or other boiler operating variables. In the limited test data obtained, the debit due to increased carbon on particulates, as discussed in Section 6.1.4 is offset at least in part by the improved boiler efficiency due to the lower excess air operation at "low NO_x" conditions. Surprisingly, there is some evidence that "low NO_x" firing techniques for tangentially fired boilers decrease carbon losses by about 25 to 40%. If this finding can be substantiated for other tangentially fired boilers, a net credit may be applied to "low NOx" operation of these units. Also it appears that "low NO_x" firing may decrease carbon losses for boilers fired with Western coals. Such improvements, however, would not be substantial since unburned combustible losses with the easy-to-burn Western coals are already low.

More data are needed on all types of boilers to substantiate these findings. It is important to note, however, that no major adverse side effects on particulate emissions appear to result from the application of staged combustion and low excess air levels for NO_x emission control for the coal fired boilers tested.

2.3 Furnace Corrosion Testing

Corrosion of furnace sidewall tubes caused problems in the early days of the development of pulverized coal firing in utility boilers. A considerable level of effort was devoted to the solution of this problem through actual field trials and in laboratory experiments to determine the corrosion mechanism. Eventually practical solutions to the furnace tube corrosion problem were found by increasing the level of excess air and improving the fineness of pulverization so that oxidation of the pyrites in the coal was complete before these ash particles could impinge on the sidewall tubes. As practical solutions to this problem became available, very little information on this subject was documented in publications.

For the purpose of reducing nitrogen oxide emissions from boilers, decreasing the level of excess air has been practical as one of the principal combustion modification techniques. The potential use of this approach has resulted in a considerable amount of speculation and apprehension that furnace sidewall corrosion problems might again be encountered in coal fired installations. Consequently, boiler owners have been reluctant to subject their units to long term tests to determine potential corrosion problems associated with low excess air firing without some evidence that the risks are not grave, particularly for staged firing that produces a net reducing environment in some portions of the furnace.

For the above reasons, part of the current program was devoted to obtaining "measurable" corrosion rates on probes exposed to actual furnace conditions. The objective of this effort was to obtain data on potential effects of "low NO_x" firing conditions on furnace wall tube corrosion rates. The approach used in obtaining these data was to deliberately accelerate the rate of corrosion of coupons exposed to temperatures in excess of normal tube metal temperatures of about 600°F. It was decided that exposure for 300 hours at 875°F in susceptible furnace areas would be sufficient to show major differences in corrosion rates between coupons exposed to "low NO_x" firing conditions and those exposed under normal conditions.

Although there was some scatter in the data obtained, the results showed some consistent trends. A major finding was that no major differences in accelerated corrosion rates were observed between coupons exposed to "low NO_x", reducing conditions and those exposed under normal boiler operating conditions. In fact, in some of the tests, the corrosion rates were found to be lower under modified combustion operation than under baseline conditions.

Since corrosion was deliberately accelerated for these corrosion tests in order to develop "measurable" corrosion rates in a short time period, the measured rates were much higher than normal tube wastage experienced in actual furnace walls. In future tests, the coupons should not be acid pickled prior to exposure in the furnace to remove oxide coatings, and coupon temperatures should be reduced to obtain corrosion rates more closely simulating actual tube wastage rates.

More information is required for assessing the importance of furnace tube corrosion problems that may result from firing coal with substoichiometric quantities of air. The data obtained in this program helps provide evidence that furnace tube corrosion may not necessarily be a severe side effect of combustion modification techniques for NO_x emission control. Long term "low NO_x" tests using corrosion probes and the direct determination of actual furnace wall tube corrosion rates by measuring tube wall thicknesses are needed for a thorough assessment of the problem.

2.4 Effects of Combustion Modifications on Boiler Performance

Modifications of the combustion process for minimizing NO_x emissions in general tend to result in less intense combustion conditions. Lowering the level of excess air supply increases flame temperatures which aids combustion, but tends to limit the amount of oxygen available for the combustion process. Thus, this factor directionally increases the probability of burnout problems. Similarly, staged combustion burner patterns, in which some burners are operated at substoichiometric conditions, and the remaining burners are used as secondary or overfire "air-ports" to complete the combustion of the fuel, can produce major changes. These consist of further limiting the supply of available oxygen in the initial combustion phase, lengthening the flames, and slower diffusive mixing of air and fuel. Thus, this mode of operation potentially increases unburned combustibles and, in turn, could have an adverse effect on boiler efficiency.

During each major test at baseline and "low NO_x" firing conditions particulate dust loading data were obtained in accordance with EPA recommended procedures. The particulate samples were analyzed for carbon content (uncombustibles) and the differences in results from tests at baseline and "low NO_x" conditions provide an indication of potential adverse side-effects. In addition, critical control room board data and other information pertinent to boiler performance calculations were recorded. Boiler efficiency was calculated for each test following the ASME Abbreviated Efficiency Test heat loss method using this information. The results are discussed in Section 6.1.4.

The conclusion reached from these performance data is that there are no major performance debits with regard to boiler efficiency when operating a boiler under "low NO_x" emission conditions. Differences discerned in boiler efficiency, if any, with "low NO_x" firing were negligible. This shows that, with proper controls, the problems discussed above can be minimized or eliminated.

2.5 NO_x Emissions for Boilers Converted from Coal to Oil Firing

Very little information is available on the level and potential control of NO_x emissions for utility boilers converted from coal to oil firing. For this reason, short-term emission tests were made on several units of this type.

This section summarizes the emission field tests conducted on utility boilers converted from coal to oil firing. Six units of this type were tested, four of them at Atlantic City Electric Company's Deepwater Station, and the other two boilers at that company's B. L. England Station.

Design and operating features of these six oil-fired boilers tested are summarized in Table 2-5. All of the boilers tested at the Deepwater Station are front-wall fired units having maximum continuous ratings ranging between 23 MW and 83 MW gross load. The two cyclone-fired boilers tested at the B. L. England Station have full load ratings of 136 MW and 168 MW, respectively.

Table 2-6 summarizes the NO_x emissions measured from these coal-to-oil converted boilers tested.

In general, low NO_x levels were measured even under normal, baseline conditions. Thus, the baseline NO_x emissions measured from Deepwater Boilers No. 3 and 5 were found to be lower than the EPA new source emission standard of 0.3 lb NO_x per million Btu fired, which is equivalent to about 225 ppm, corrected to 3% O_2, on a dry basis. For Deepwater Boilers No. 8 and 9, the baseline NO_x emissions were found to be slightly above the 0.3 lb/10^6 Btu level, but staged firing of these boilers reduced the emissions from these boilers well below the level of 0.3 lb/10^6 Btu.

As expected, the cyclone fired coal-to-oil converted Boilers No. 1 and 2 at ACE's B.L. England Station produced significantly higher NO_x emissions than the wall-fired units tested at Deepwater. In the case of B.L. England No. 1, the baseline level was 441 ppm NO_x (corrected to 3% O_2, on a dry basis), compared with the 225 ppm equivalent of the 0.3 lb/10^6 Btu recommended EPA standard. Similarly, the baseline NO_x emissions level from B.L. England Boiler No. 2 was 361 ppm, corrected to 3% O_2 on a dry basis. This is in line with the expected effect of the high temperature environment prevailing in cyclone fired boilers, which are conducive to relatively high NO_x emission levels.

Staged firing of front wall fired Boilers No. 8 and 9 at the Deepwater Station produced NO_x emission levels well below the 0.3 lb/10^6 Btu level, even at full boiler load. Lowering the excess air level was effective in all boilers tested (including the cyclone boilers), for reducing NO_x emissions, particularly in combination with staged firing.

The relative contribution of atmospheric nitrogen fixation and chemically bound nitrogen oxidation NO_x emissions can be estimated based on the data of Turner et al., obtained in a modified packaged boiler (8). The fuel oils fired at Deepwater averaged about 0.13 wt. % N content. According to the fuel nitrogen conversion data, about 70% of the nitrogen in the fuel is expected to be converted into NO_x. Thus, roughly 130-140 ppm NO_x would be predicted to be produced through the oxidation of fuel nitrogen. When comparing this prediction with the actual NO_x levels measured, it appears that in all cases fuel nitrogen oxidation accounts for significant portions, and in some cases, the bulk of the NO_x emission. Similar arguments can be made about the cyclone fired boilers at the B.L.

TABLE 2-5

ATLANTIC CITY ELECTRIC COMPANY

SUMMARY OF COAL-TO-OIL CONVERTED BOILERS TESTED

Station	Blr No.	Blr Mfr.	Type of Firing	MCR (MW)	No. of Burners	Test Variables	No. of Test Runs
Deepwater	3	B&W	FW	57	6	5	8
Deepwater	5	B&W	FW	56	6	4	4
Deepwater	8	B&W	FW	83	16	14	25
Deepwater	9	CE	FW	22.8	6	6	7
B. L. England	1	B&W	Cyc.	133	3	4	7
B. L. England	2	B&W	Cyc.	168	4	2	2

TABLE 2-6

ATLANTIC CITY ELECTRIC COMPANY

SUMMARY OF NO_x EMISSIONS FOR COAL-TO-OIL CONVERTED BOILERS

Boiler	Operating Mode (Gross Load-MW)	% O_2	NO_x Emissions			CO
			ppm (3% O_2)	lb / 10^6 Btu	Gr/10^6 Cal	ppm (3% O_2)
Depwater No. 3	Baseline (57)	6.1	142	--	--	67
	"Low NO_x" (57)	5.0	118	--	--	81
Deepwater No. 5	Baseline (56)	4.2	221	0.29	0.52	55
	"Low NO_x" (56)	2.8	209	0.28	0.50	84
Deepwater No. 8	Baseline (83)	4.5	246	0.33	0.59	49
	"Low NO_x" (81)	4.4	123	0.16	0.29	64
Deepwater No. 9	Baseline (23)	1.8	286	0.38	0.68	44
	"Low NO_x" (21)	2.6	101	0.13	0.23	64
B. L. England No. 1	Baseline (133)	1.5	441	0.59	1.06	57
	"Low NO_x" (132)	0.5	313	0.42	0.76	1523
B. L. England No. 2	Baseline (167)	2.2	361	0.48	0.86	85
	"Low NO_x" (167)	1.6	303	0.42	0.76	231

England Station, where fuel nitrogen contribution to NO_x emissions is expected to be significant, but proportionately less because of the more intense combustion conditions. Therefore, the use of combustion modification techniques, if possible on cyclone fired installations might become necessary if high nitrogen content fuel oils or other liquid fuels (such as coal liquids or shale oil) are fired in such boilers.

In conclusion, much valuable information has been obtained in this test program on the levels of NO_x emissions and their potential control in boilers converted from coal to oil firing. Although further emission data are needed for establishing broad generalizations for this type of equipment, it may be concluded that the NO_x response of such units to combustion modifications is similar to that of boilers designed for oil firing. In fact, the furnace characteristics of coal-fired boilers converted to oil firing are expected to favor the control of NO_x emissions through combustion modifications, because of the more liberal sizing of coal fired furnaces, which should result in higher heat removal rates when firing oil.

3. EFFECT OF ELECTROSTATIC PRECIPITATORS ON NO_x FORMATION

Electrostatic precipitators are used extensively for reducing particulate emissions for coal fired, steam-electric plants. High voltages across electrodes in this equipment create a corona discharge that ionizes gas molecules and electrically charges particles passing through the field. The charged particles are attracted to oppositely charged surfaces where they can be removed from the flue gas.

The effect of electrostatic precipitation on NO_x formation is not clear. It is possible that the corona discharge (or perhaps arcing) forms ozone and atomic oxygen, which form nitrogen oxides through reactions with nitrogen. However, data reported to date have not resolved this question since both increases and decreases of NO_x have been found (1).

As part of the present field test program, emission measurements were made upstream and downstream of the precipitator in the A and B flue gas ducts of Boiler No. 4 at the Barry Power Station of the Alabama Power Company, in an attempt to shed more light on this potential problem. The precipitators of Boiler No. 4 at the Barry Station are well suited to such tests, as the ash removal system at present is incapable of removing the flyash collected in the precipitator collection hoppers sufficiently rapid. This results in a build-up to a point where the plates are shorted and arcing occurs. It has been expected that this condition may promote the formation of NO_x, if any occurs.

Table 3-1 summarizes gas analyses taken before and after the Barry A and B precipitators with the precipitators on and off. All data reported have been corrected to 3% O_2 in the flue gas for comparison purposes. Analysis of the data shows that there are no statistically significant differences in NO_x values measured upstream and downstream of the precipitators on either the A or B sides. It is concluded from these tests that either the conditions required for the formation of NO_x in precipitators were not present in these tests, or more likely, that there is no net production of NO_x from the precipitators. Additional research, over a variety of both corona discharge as well as arcing operations is needed to better quantify the effect of electrostatic precipitators on NO_x formation in flue gas from coal fired boilers.

As reported earlier in our "Systems Study" (1), electric discharge precipitation has been successfully used to remove NO from manufactured gas (10). However, it appears that unsaturated hydrocarbons are essential for NO removal (11) by this method. Since power plant flue gases contain negligible amounts of unsaturates, such compounds would have to be added at prohibitively high costs to use such a proposed method (12) for power plant NO_x emission control.

TABLE 3-1

NO_x EMISSION MEASUREMENTS TESTS ACROSS THE ELECTROSTATIC PRECIPITATOR

ALABAMA POWER COMPANY BARRY, BOILER NO. 4

(NO_x Concentrations in ppm, Corrected to 3% O_2, Dry Basis)

I. Precipitator Off - A Side

	Before Precipitator			After Precipitator	
	Probe 1	Probe 2		Port a	Port b
	414	388	Short	386	401
	401	380	Medium	373	414
	407	381	Long	376	422
Avg.	407	383	Ave.	378	412
Avg.	395		Avg.	395	

II. Precipitator On - A Side

	Before Precipitator			After Precipitator	
	Probe 1	Probe 2		Port a	Port b
	428	417	Short	420	416
	431	424	Medium	421	416
	436	416	Long	429	427
Avg.	432	419	Ave.	423	420
Avg.	426		Avg.	422	

III. Precipitator Off - B Side

	Before Precipitator			After Precipitator	
	Probe 1	Probe 2		Port a	Port b
	389	371	Short	373	383
	400	387	Medium	404	392
	405	399	Long	392	393
Avg.	398	386	Ave.	390	389
Avg.	372		Avg.	394	

IV. Precipitator On - B Side

	Before Precipitator			After Precipitator	
	Probe 1	Probe 2		Port a	Port b
	411	404	Short	398	379
	411	464	Medium	400	387
	413	406	Long	403	394
Avg.	412	405	Ave.	400	387
Avg.	408		Avg.	394	

4. FIELD STUDY PLANNING AND PROCEDURES

This section discusses the major steps involved in field study planning and the test procedures used to obtain emission and corrosion measurements. Field study planning steps included developing boiler selection criteria, establishing EPA/Exxon/Boiler Operators/Boiler Manufacturers cooperation, and designing an effective test program strategy. Testing procedures included gaseous sampling and analyses, particulate sampling and corrosion probing. Methods of gaseous emission testing were quite similar to those used in Exxon's "Systematic Field Study" (4-6). Particulate loadings of the flue gas stream, and the carbon content of the particulates were also determined to identify potentially adverse side-effects. In addition, corrosion probes were designed, and acclerated corrosion test measurements were conducted under baseline and low NO_x operations.

4.1 Program Design

As discussed earlier in this report, the major problem area in reducing NO_x emissions by combustion modification is to apply such techniques to coal fired boilers. Coal fired utility boilers are the largest single source of stationary NO_x emissions in the United States, i.e., 3 million tons NO_x estimated for 1970, compared to 0.5 million tons for gas, and 0.3 million tons for oil firing (1). The operating flexibility of coal fired boilers is generally less than that of oil or gas fired boilers. This section will discuss the criteria developed and the cooperative efforts required for selecting representative coal fired boilers, as well as the broad testing program strategy developed for efficiently measuring gaseous emissions, particulate emissions, and accelerated corrosion rates.

4.1.1 Boiler Selection Criteria

Criteria recommended for selection of coal fired boilers were classified into five groups which are discussed in turn below: (1) boiler design factors, (2) boiler operating flexibility, (3) boiler measurement and control capability, (4) boiler operating management policy concerning research and operating practices and (5) logistic and scheduling considerations.

Boilers representing the current design practices of the utility boiler manufacturers (Babcock and Wilcox, Combustion Engineering, Foster Wheeler and Riley-Stoker) were desired. Design factors such as size (150 MW or larger), type of firing (wall tangential, turbo-furnace and possibly cyclone), furnace loading (normal, not extreme), burner configuration (size, number and spacing), draft system (both balanced draft and pressurized), and furnace bottom design (wet and dry bottom) were considered.

Boiler operating flexibility was a prime consideration in selecting boilers. Specific variables (with the desired operating ranges listed in parentheses) were: excess air level (5-30%), furnace load with all burners firing (60 to 100% of maximum continuous rating), staged firing (individual burners or rows of burners on air only, or biased firing of individual burners), air register settings (20% to 100% open), combustion air preheat temperature (100°F variation), wind box pressure (low to high, over wide ranges of furnace load and excess air levels), fuel burned (coal types characteristic of major U.S. regions), flue gas recirculation (location of injection point and amount recirculated) and independent steam temperature controls (attemperation water, burner tilt, air register flexibility, adequate soot blower capacity, etc.).

Boilers varv considerably with regard to their operating parameters, and measurement and control capabilities. These capabilities are needed to assure accurate, quantative measurements representing each operating condition, and to maintain stable operations during each test run. Key measurements needed are fuel, air and water temperatures and feed rates; steam temperatures, pressures and flow rates; and flue gas component measurements of oxygen, combustibles, smoke, and temperatures. In addition, furnace viewing ports should be available for visual inspection of furnace conditions such as burner flames and slag buildup, in order to monitor potential problem areas during each test run. Also, ports are needed for sampling coal supplied to or from the pulverizers, sampling the flue gas before air preheaters, sampling particulates before precipitators, and for inserting corrosion probes in furnace sidewalls.

The attitude of the utility station operating management towards research programs, and their operating practices are other key elements affecting the productivity of field programs. Operating management support includes providing the necessary technical, supervisory and operating personnel for both planning and conducting the test program. "Research-mindedness" means support for exploiting the full range of boiler operating flexibility in the test program. A willingness to schedule boiler load changes, to provide expert help in pre-test boiler checkout, including the calibration of key boiler instruments, and to use experienced plant people for coal sampling and analysis is the result of a constructive management policy towards research programs.

The criteria discussed above are extremely useful in selecting candidate boilers for testing. Individual boilers can then be selected to provide maximum overall program effectiveness and efficiency by taking into account total schedule and logistic considerations. Thus, utilities and stations should be so selected that they would offer a number of boilers suitable for testing to minimize travel and set-up time, and provide flexibility in case of unplanned boiler shutdowns, with appropriate availability and load range.

4.1.2 EPA/Exxon/Boiler Operators/ Boiler Manufacturers Cooperation

This cooperative program of field testing utility boilers was conducted by Exxon Research with the cooperation of utility boiler operators and manufacturers under the coordination of EPA. The proper selection of boilers representing current design practices for this program was the result of a cooperative planning effort. Exxon Research developed the comprehensive list of selection criteria discussed above to assist EPA and boiler manufacturers in preparing a list of potential boiler candidates. Each boiler manufacturer submitted a list of suggested boilers to EPA for review and screening. After consideration of such factors as design variables, operating flexibility, fuel type, geographic location and logistics, a tentative list of boilers was selected by EPA and Exxon. Field meetings were then held at power stations to confirm the validity of the boilers selected and to obtain necessary boiler operating and design data.

The field meetings were attended by representatives of EPA, Exxon Research, boiler manufacturers and utility boiler operating management. EPA described the background and need for developing emission control technology for coal fired boilers, and how this fits into the overall EPA program. Exxon Research presented a broad summary of previous findings, and an outline of the three-phase program to be run at each boiler. This led to the discussion aimed at developing the information necessary to construct a detailed program plan. These discussions produced a mutually agreeable list of combustion operating variables, the specific levels to be tested, estimated ease and length of time to change from one level to another, how the variables were interrelated, and what operating limitations or restrictions might be encountered. In addition, the proper number and specific location of sampling ports for gaseous, particulate, and corrosion probes were also agreed upon. If existing sampling ports were not adequate, new ports were installed by the utility. Tentative testing dates were scheduled with provisions made for possible segregation of coal types, scheduling of pre-test boiler inspection, calibration of measuring instruments and controls, scheduled maintenance, and other preparatory steps.

The excellent support and cooperation provided by boiler manufacturers and utility boiler operators contributed significantly to the success of this program.

4.1.3 Test Program Strategy

The up-to-date, comprehensive information obtained in field meetings provided the necessary data for Exxon to develop detailed, run-by-run, proposed test program plans for review by all interested parties. Each test program, tailored to take full advantage of the particular combustion control flexibility of each boiler, was comprised of three phases: (1) short test-period runs, (2) a 1-3 day sustained "low NO_x" run and (3) 300-hour sustained "low NO_x" and normal operation runs. Thus the strategy used for field testing coal-fired boilers consisted first, of defining the optimum operating conditions for NO_x emission control, without apparent unfavorable side effects in short-term statistically designed test programs. Second, the boiler was operated for 1-3 days under the "low NO_x" conditions determined during the optimization phase, for assessing boiler operability problems. Finally, where possible, sustained 300-hour runs were made under both baseline and modified ("low NO_x") operating conditions. During this period, air-cooled carbon steel coupons were exposed on corrosion probes in the vicinity of furnace water tubes, to determine through accelerated corrosion tests whether operating the boiler under the reducing conditions associated with staged firing results in increased furnace water tube corrosion rates. Particulate samples were obtained under both baseline and "low NO_x" conditions. Engineering information on boiler operability, e.g., on slagging problems, and data related to boiler performance were also obtained.

Statistical principles (as discussed in more detail in our "Systematic Field Study" (4)) provided practical guidance in planning the Phase 1 test programs, i.e., how many, and which test runs to conduct, as well as the proper order in which they should be run. These procedures allow valid conclusions to be drawn from analysis of data on only a small fraction of the total possible number of different test runs that could have been made. Table 4-1 will be used to illustrate briefly these principles applied to a front-wall fired boiler, TVA's Widows Creek Boiler No. 6. (Tangentially fired boilers present a more complex problem in experimental planning, since there are additional operating variables such as burner tilt and secondary air register settings, that should be included in the experimental design. However, the same statistical principles apply. In this example, there are four operating variables: (1) load, (2) excess air level, (3) secondary air register settings, and (4) burner firing pattern. Assuming three levels of each of the first three variables, and eight different firing patterns available at each load, there are 216 different operating modes. However, only the 33 test runs shown, i.e., 15% of the potential maximum, provided the required information on this boiler to define practical "low NO_x" operating conditions.

Test run No. 10 operating conditions were chosen for the second phase of the experimental program, while test run No. 26 operating conditions are recommended for "low NO_x" operation under reduced load conditions. Test run No. 10 conditions could be selected with considerable confidence, since examination of the data indicates that each of the S_3 firing pattern runs produced lower NO_x levels than did the corresponding S_2 firing pattern. The effects of day-to-day variables, such as coal type variability, etc. not under study were balanced between the two firing patterns, since runs No. 5, 6, 7 and 8 were made on one day, while runs No. 9, 10, 11 and 12 were run on another day. It should also

TABLE 4-1

TEST PROGRAM EXPERIMENTAL DESIGN - WIDOWS CREEK, NO. 6

(Run No., Average % O_2 and Average PPM NO_x Emissions (3% O_2, Dry))

	L_1 - Full Load (125 MW)				L_2 - Reduced Load (80 - 110 MW)			
	A_1 - Normal Air		A_2 - Low Air		A_1 - Normal		A_2 - Low Air	
Firing Pattern / Secondary Air	20% Open	60% Open	20% Open	60% Open	20% Open	60% Open	20% Open	60% Open
S_1 - 16 Coal 0 Air Only	(3) 2.8% 610	(1) 3.2% 577	(4) 1.9% 505	(2) 2.0% 491	(31) 4.9% 681	(29) 4.8% 629	(32) 2.8% 464	(30) 2.7% 450
S_2 - 14 Coal D_1D_4 Air	(11) 3.8% 632	(5) 4.0% 558	(6) 2.0% 372	(12) 1.5% 406				
S_3 - 14 Coal A_1A_4 Air	(7) 4.5% 532	(9) 4.1% 518	(10)* 1.7% 345	(8) 2.7% 368				
S_4 - 12 Coal $A_1A_3A_3A_4$					(24) 4.5% 399	(13) 4.5% 460	(26)** 2.7% 297	(20) 3.0% 345
S_5 - 12 Coal $A_1A_4B_2B_3$					(27) 4.9% 496	(17) 4.4% 480	(22) 3.4% 306	(14) 2.6% 342
S_6 - 12 Coal $A_1A_4B_1B_4$					(15) 5.2% 471	(21) 6.1% 550	(19) 3.1% 301	(28) 4.5% 438
S_7 - 12 Coal $A_1A_4D_1D_4$					(18) 4.3% 418	(25) 4.5% 495	(16) 2.9% 329	(23) 3.9% 438
S_8 - 12 Coal $B_1B_2B_3B_4$								(20A) 2.2% *** 371

* "Low NO_x" operation selected for sustained run.

** "Low NOx" operation at reduced load

*** Unplanned run 20A was conducted to obtain additional information when pulverizer B was down due to mechanical problems.

Pulverizer-Burner Configuration				
Mill	Burner No.			
	1	2	3	4
A-Top Row	0	0	0	0
B-2nd Row	0	0	0	0
C-3rd Row	0	0	0	0
D-Bot. Row	0	0	0	0

be noted that each day's runs completed a one-half replicate of the complete factorial accomplished by two days of testing. Thus, the main effects of each factor and interactions between factors could be estimated independently of each other, with maximum precision. Repeat test runs under test run 10 conditions, during a two-day sustained period, were used to validate these results and to obtain an independent estimate of experimental error.

4.2 Test Procedures

This section of the report describes the procedures used for performing field tests on utility boilers. Flue gases were sampled and analyzed for gaseous species in each of the boiler test programs. To assess potentially adverse side-effects of combustion modification techniques on particulate emissions (including carbon losses in the flyash) and on furnace water-wall corrosion rates, particulate measurements and accelerated corrosion rate determinations were also made for a number of boilers tested in this study.

4.2.1 Gaseous Sampling and Analysis

The objective of obtaining reliable gaseous emission data in field testing boilers requires a sophisticated sampling system. The sampling and analytical system used in this program has already been described in detail in the Esso Research and Engineering Company Report, "Systematic Field Study of NO_x Emission Control Methods for Utility Boilers" (4).

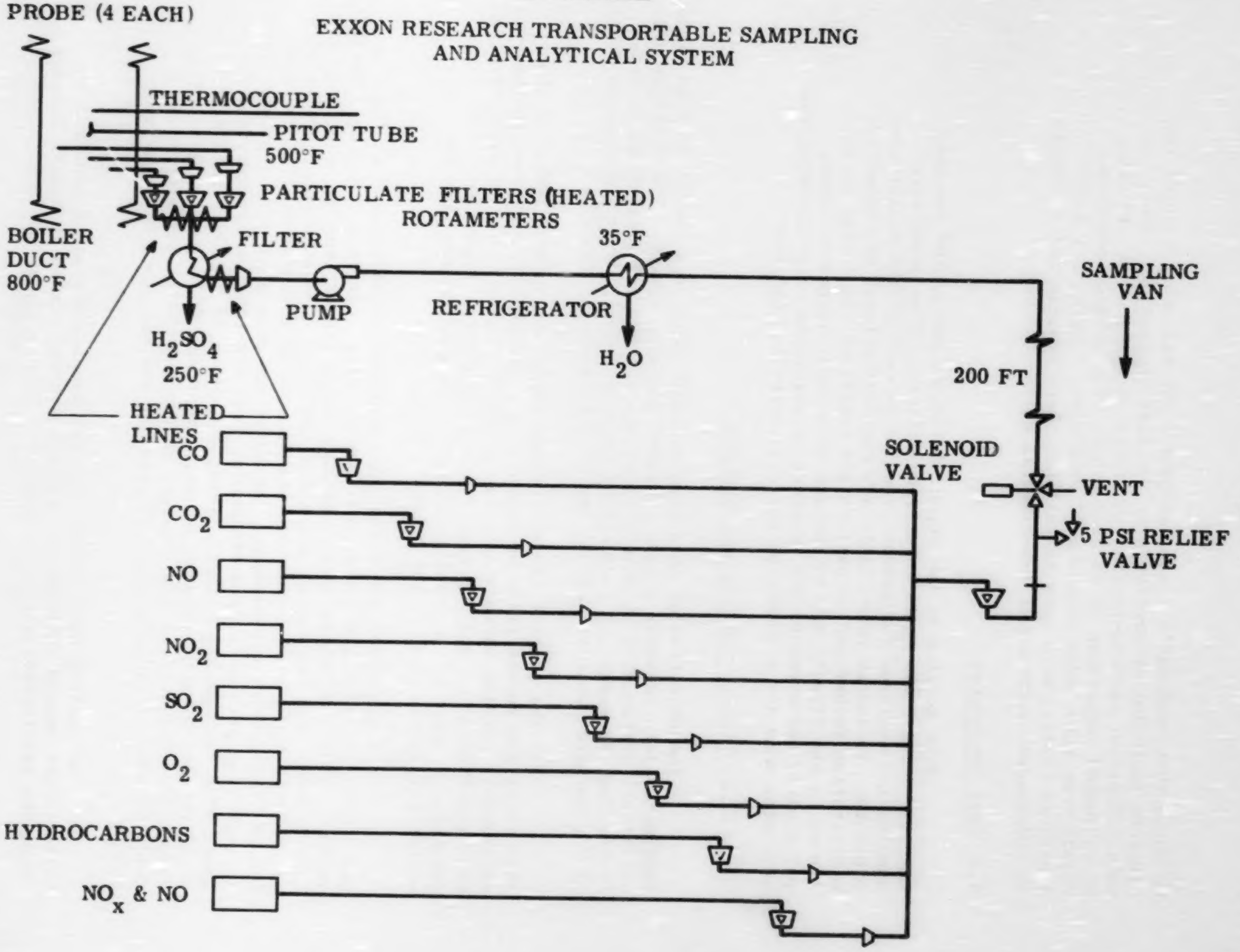
For the present study, further capabilities were added to the analytical instrument train by installing a Thermo-Electron chemiluminescent analyzer to provide measurements of NO and NO_x in addition to those obtained with the Beckman NO and NO_2 spectroscopic monitors. Figure 4-1 is a schematic diagram of the configuration of the gaseous sampling and analytical system used in the present study.

Since samples are taken from zones of "equal areas" in the flue gas ducts, gas sampling probes are "tailor-made" for each individual boiler tested. Three stainless steel sampling tubes (short, medium, and long) are fabricated on the test-site, and installed in quick-disconnect mounting probe assemblies, along with a thermocouple located at the mid-point of the duct for gas temperature measurement. At least two probes of this type are installed in each flue gas duct, or a minimum of four are used when there is only one large flue duct on the boiler. Thus, a minimum of 6 sample points per duct, or 12 per boiler are provided, assuring representative gas samples. All connections between the Esso Analytical Van and the probes are of the quick-disconnect type for ease of assembly and assurance of leak-proof joints.

In running field tests, the gas samples are withdrawn from the boiler under vacuum, through the stainless steel probes to heated filters where the particulate matter is removed. These filters are maintained

FIGURE 4-1

EXXON RESEARCH TRANSPORTABLE SAMPLING AND ANALYTICAL SYSTEM


PROBE (4 EACH)
THERMOCOUPLE
PITOT TUBE
500°F
PARTICULATE FILTERS (HEATED)
ROTAMETERS
BOILER
DUCT
800°F
FILTER
H_2SO_4
250°F
HEATED
LINES
PUMP
35°F
REFRIGERATOR
H_2O
SAMPLING
VAN
200 FT
SOLENOID
VALVE
VENT
5 PSI RELIEF
VALVE
CO
CO_2
NO
NO_2
SO_2
O_2
HYDROCARBONS
NO_x & NO

at 300-500°F. The gases then pass through rotameters, which are followed by a packed glass wool column for SO_3 removal. Initially, gas temperatures are kept as high as possible to minimize condensation in the particulate filters. After leaving the packed column at 250-300°F, the gas samples pass at temperatures above the dew-point through heated Teflon lines to the vacuum/pressure pumps. The sample is then refrigerated to a 35°F dew-point before being sent to the van for analysis. Usually, the van is located 100 to 200 feet from this point and the gas stream flows through Teflon lines throughout this distance.

As in our previous studies (4-6), our analytical van was equipped with Beckman non-dispersive infrared analyzers to measure NO, CO, CO_2 and SO_2, a non-dispersive ultraviolet analyzer for NO_2 measurement, a polarographic O_2 analyzer and a flame ionization detector for hydrocarbon analysis. The Thermo-Electron chemiluminescent instrument, as indicated above, was added to provide improved capabilities for NO and NO_x measurements. The measuring ranges of these continuous monitors are listed in Table 4-2.

A complete range of calibration gas cylinders in appropriate concentrations with N_2 carrier gas for each analyzer is installed in the system. Instruments are calibrated daily before each test, and in-between tests if necessary, assuring reliable, accurate analyses.

Boiler flue gas samples are pumped continuously to the analytical van through four probes, each of which combines the effluent of three individual sampling tubes. While one sample is being analyzed, the other three are being vented. Switching to a new sample requires only the flushing of a very short section of sample line before reliable readings may be obtained. Four duplicate sets of analyses from each probe can be obtained in less than 32 minutes, thus speeding up the task of obtaining reliable gaseous emissions, and/or avoiding the need to hold the boiler too long at steady state conditions.

The validity of using the Thermo-Electron chemiluminescent NO/NO_x analyzer as the primary NO_x monitoring instrument was checked during the first series of tests conducted in this program, on TVA's Widows Creek Boiler No. 6. As shown in Figure 4-2, the NO_x data measured with the chemiluminescent analyzer were correlated with the sum of NO plus NO_2 data measured with the Beckman non-dispersive infrared NO and non-dispersive ultraviolet NO_2 instruments. As seen from the regression in Figure 4-2, excellent agreement was obtained between the chemiluminescent monitor was validated against the spectroscopic instruments, which in turn had been validated against a variety of other technqiues, including the wet chemical phenoldisulfonic acid method, in previous Exxon field studies (4-6).

Our instrumental measurement technique for flue gas O_2 and CO_2 analyses were validated periodically by checking against Orsat determinations made on samples taken from the same points. Measured O_2 vs. CO_2

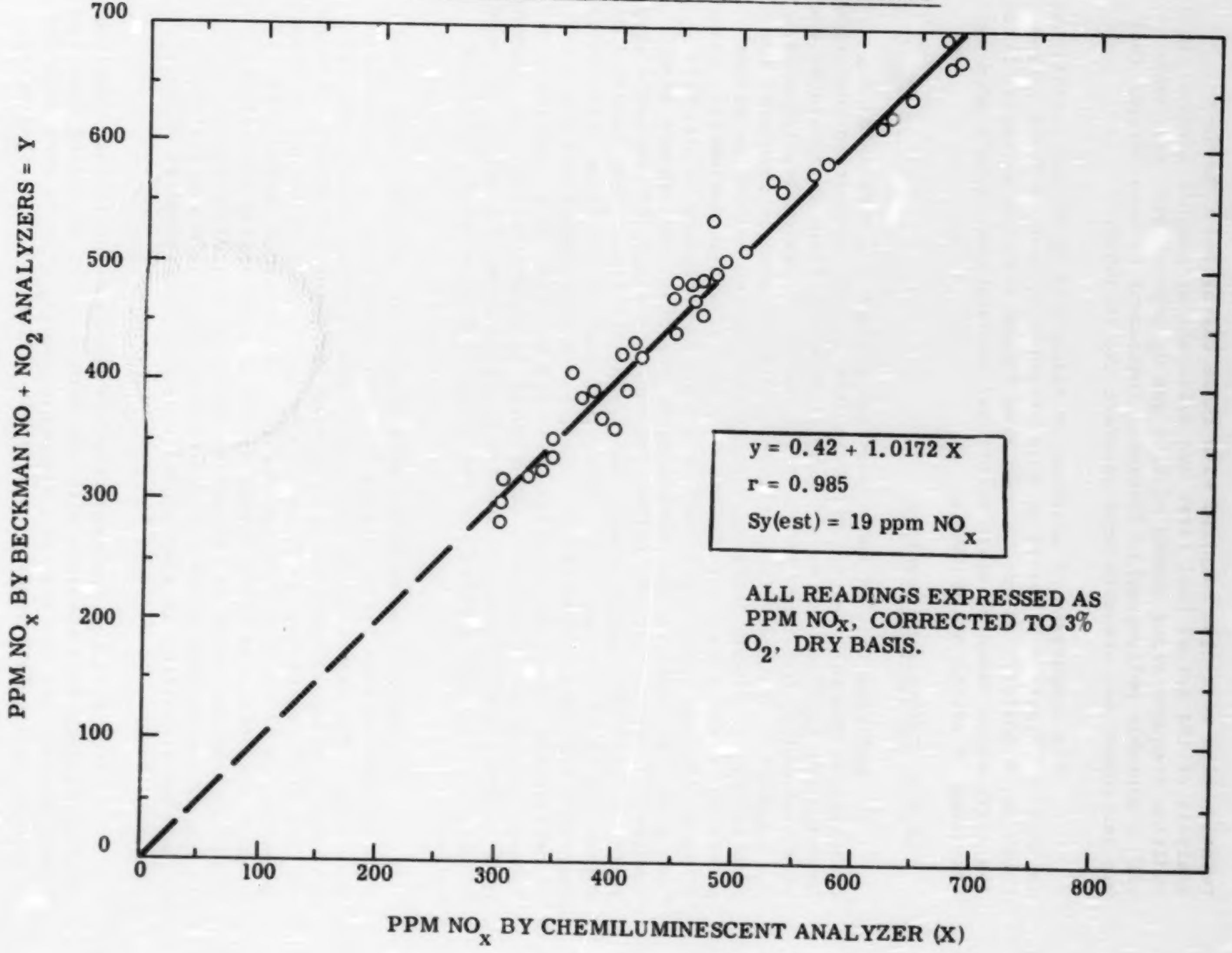
TABLE 4-2

CONTINUOUS ANALYTICAL INSTRUMENTS IN EXXON VAN

Beckman Instruments	Technique	Measuring Range
NO	Non-dispersive Infrared	0-400 ppm 0-2000 ppm
NO_2	Non-dispersive ultraviolet	0-100 ppm 0-400 ppm
O_2	Polarographic	0-5% 0-25%
CO_2	Non-dispersive infrared	0-20%
CO	Non-dispersive infrared	0-200 ppm 0-1000 ppm 0-23,600 ppm
SO_2	Non-dispersive infrared	0-600 ppm 0-3000 ppm
Hydrocarbons	Flame ionization detection	0-10 ppm 0-100 ppm 0-1000 ppm
Thermo Electron		
NO/NO_x	Chemiluminescent	0-2.5 ppm 0-10.0 ppm 0-25 ppm 0-100 ppm 0-250 ppm 0-1000 ppm 0-2500 ppm 0-10,000 ppm

FIGURE 4-2

NO_x REGRESSION - BECKMAN NO + NO_2 VS CHEMILUMINESCENCE NO_x MEASUREMENTS



relationships were also compared with those calculated from the analysis of the actual fuel fired and different excess air levels. In addition frequent cross checks of flue gas O_2 content were also made with a portable polarographic (Beckman) instrument to make certain that van instrument measurements were accurate and reliable.

The comparison of measured to calculated O_2 vs. CO_2 relationships is shown in Figure 4-3, based on data obtained in testing TVA's Widows Creek No. 6 Boiler. As can be seen from Figure 4-3, the agreement between the regressions based on measurements and calculations is very good over the range of actual measurements.

4.2.2 Particulate Sampling

Modifications of the combustion process for minimizing NO_x emissions in general tend to result in less intense combustion conditions. Lowering the level of excess air supply increases flame temperatures which aids combustion, but tends to limit the amount of oxygen available for the combustion process. Thus, this factor directionally increases the probability of burnout problems. Similarly, staged combustion burner patterns, in which some burners are operated at sub-stoichiometric conditions, and the remaining burners are used as secondary or overfire "air-ports" to complete the combustion of the fuel, can produce major changes. These consist of further limiting the supply of available oxygen in the initial combustion phase, lengthening the flames, and slower diffusive mixing of air and fuel. Thus, this mode of operation potentially increases unburned combustibles. Also, the actual amount and character of particulate matter in the flue gases may be affected by modified combustion operation. Therefore, it appeared necessary to take into account that combustion modifications applied for minimizing NO_x emissions could potentially increase particulate emissions from pulverized coal-fired boilers.

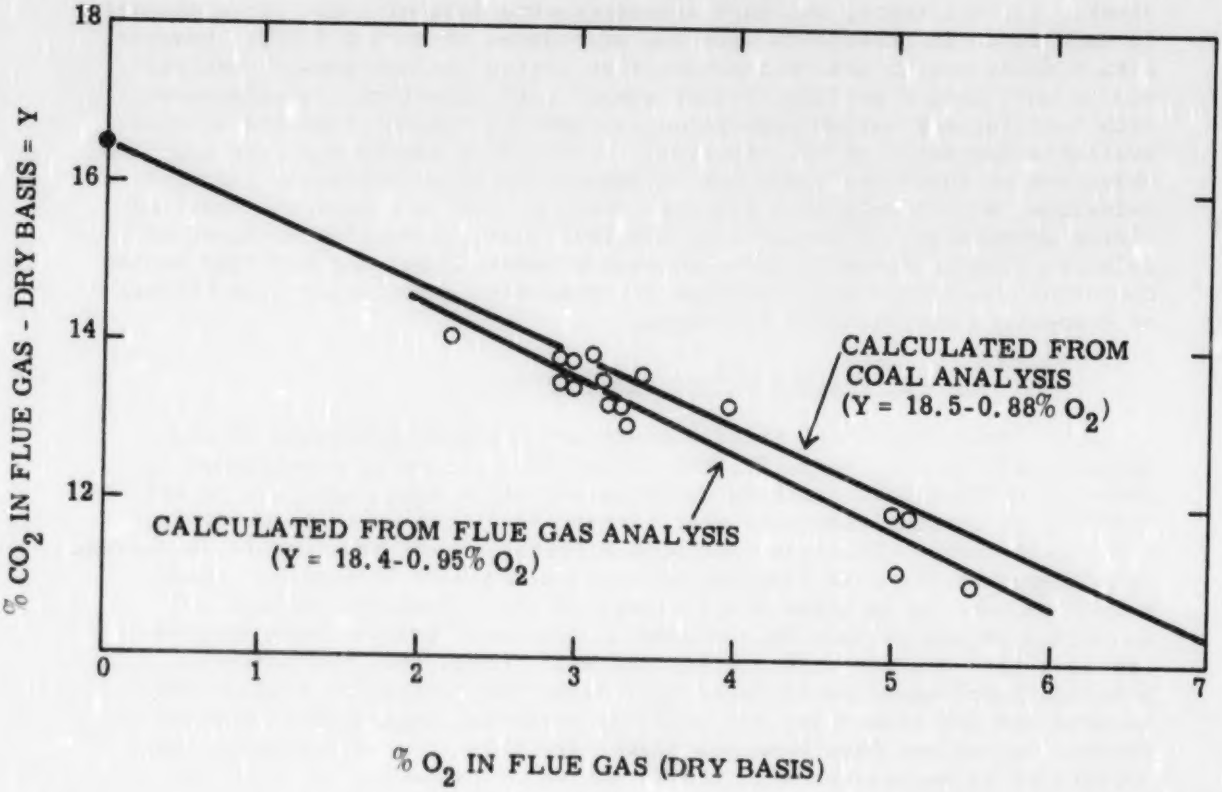
To satisfy the need for this type of information, this field test program on coal fired boilers included measurement of particulate emissions. The objective of this effort was to obtain sufficient particulate loading information to determine the potential adverse side effects of "low NO_x" combustion modifications on particulate emissions by comparing measurements of total quantities and per cent unburned carbon with similar data obtained under normal or baseline operating conditions. Other information, such as changes in particle size distribution or in flyash resistivity which could affect electrostatic precipitator collection efficiency is also needed. However, measurements of this type were beyond the scope of the present program.

Four Research Appliance Company EPA-type particulate sampling trains designed in accordance with EPA Method 5 (9), including four sample boxes, probes, and two sets of isokinetic pumping systems were used for obtaining particulate loading data on six pulverized coal fired utility

FIGURE 4-3

RELATIONSHIP BETWEEN % CO_2 AND % O_2 FLUE GAS MEASUREMENTS

(WIDOWS CREEK, BOILER NO. 6-1B)



boilers. The names of the utilities and details of the boilers tested for particulate emissions are indicated in Table 2-1. Except for tests at Utah Power & Light Company's Naughton Station, Boiler No. 3, all particulate mass data for dry, filterable solids loadings were obtained in the ducting at convenient locations downstream of the air-heaters. At the Naughton Station particulate testing was done upstream of the air-heaters, due to the inaccessibility of sampling locations downstream of the air heaters. Furthermore, at Alabama Power Company's Barry Station Boiler No. 4 particulate sampling was carried out downstream of the precipitator (with the precipitator shut off), in a location immediately before entering the stack. For all tests, two duct traverses were made with one probe assembly in each duct, in accordance with the procedures of Method 5 (9). However, strict adherence to EPA-recommended test method was not always possible due to the limited availability of sample port locations, interferences with building and boiler appurtenances, and the limited time and manpower available for these tests. However, it should be remembered that the objective of these tests was not to measure absolute values of particulate emissions, but to determine relative changes between normal and modified firing operations. Therefore, it was felt that information obtained on relative changes in particulate emissions under normal and modified boiler operating conditions would suffice for determining potential side-effects of combustion modification techniques.

4.2.3 Furnace Corrosion Rate Measurements

Pulverized coal fired boilers are subject to wastage of the furnace wall tubes. Normally, this type of corrosion is experienced in areas where localized reducing environments might exist adjacent to the midpoint of furnace sidewalls near burner elevations where flame impingement could occur. To counteract such effects, normal practice is to increase the excess air level so that an oxidizing atmosphere prevails at these locations, and to increase the fineness of pulverization, so that the oxidation of the pyrites in the coal is completed before these species can come into contact with the furnace wall tubes. For new boilers, a design improvement consists of increasing the separation between the burners and the sidewalls, for minizing potential impingement problems. Several mechanisms have been postulated for this type of corrosion which appears to be associated with the formation of pyrosulfates from the coal ash (at 600-900°F), and iron sulfide, or SO_3 from the pyrites.

Combustion modifications for NO_x emission control are generally most effective at low excess air or substoichiometric air supply conditions in the flame zone, i.e., under conditions that are potentially conducive to furnace tube wall corrosion. Our prior field tests of coal-fired boilers have been of short duration, allowing no time to assess such side-effects. However, the need for evaluating the effects of modified firing operations on furnace tube wall corrosion has been recognized (13). Discussions with boiler manufacturers and operators indicated that this potential problem was one of their major concerns.

Also it became evident that accelerated corrosion rate testing would be necessary to establish that staged combustion could be used in coal-fired boilers without creating corrosion problems, because of the reluctance to operate on a long-term basis using the boiler as a test medium.

Accordingly, a third aspect of our field testing was to design and construct corrosion probes, for exposure under controlled conditions to define the extent of the potential corrosion problem. The objective of our furnace corrosion probing runs was to obtain "measurable" corrosion rate data to determine potential side effects of "low NO_x" firing conditions on furnace wall tubes.

The approach used for obtaining corrosion rate data was to expose corrosion probes inserted into available openings located at "vulnerable" areas of the furnace under both baseline and staged firing conditions. Based on general corrosion probing experiments, it was concluded that exposure for approximately 300 hours at elevated coupon metals temperatures (above normal furnace tube metal temperatures of about 600°F) to accelerate corrosion, would produce "measurable" rates of corrosion on SA-192 carbon steel coupon material, used for the manufacture of furnace water tubes. Since our objective was to show relative differences in corrosion, between baseline and "low NO_x" firing, exposure temperatures at both conditions were set at approximately 875°F. Compared with normal tube wall temperatures this was sufficiently high to accelerate the rate of corrosion. At the same time, the comparison temperature was kept below the 900°F limit above which pyrosulfates apparently are not formed.

Figures 4-4 and 4-5 show details of the corrosion probes developed for this study based on a design supplied by Combustion Engineering. Essentially, this design consists of a "pipe within a pipe", where the cooling air from the plant air supply is admitted to the ring-shaped coupons exposed to furnace atmospheres at one end of the probe, through a 3/4-inch stainless steel tube roughly centered inside of the coupons. The amount of cooling air is automatically controlled to maintain the desired set-point temperature of 875°F for the coupons. The cooling air supply tube is axially adjustable with respect to the corrosion coupons, so that temperatures of both coupons may be balanced. To simplify the presentation, thermocouples mounted in each coupon are not shown in Figures 4-4 and 4-5. Normally, one thermocouple is used for controlling and the other one for recording temperatures. The cooling air travels backwards along the 2-1/2-inch extension pipe and discharges outside of the furnace. Thus, the cooling air and the furnace atmosphere do not mix at the coupon location.

A 1/4-inch stainless steel tube is provided in the probe assembly (Figures 4-4 and 4-5) with an opening on the furnace side in the vicinity of the furnace wall tubes and corrosion coupons. Furnace gases may be drawn through this sampling tube for analysis to determine the type of atmosphere (reducing or oxidizing) prevailing at the coupon location. Sampling at the various probes during corrosion testing always showed a net excess of oxygen. Normally the CO levels measured at these locations were low but in a few cases they exceeded the upper range of the CO instrument (23,000 ppm). This happened (as expected) when measured O_2 concentrations (0.1-0.2%) were very low. Therefore, in these isolated instances the atmosphere was net reducing because of the net excess of CO over oxygen.

Sustained, 300-hour corrosion probe tests were run on boilers of four utility companies, as shown in Table 4-3.

TABLE 4-3

SUMMARY OF CORROSION PROBING TESTS

Utility	Station	Boiler Number Base	Boiler Number "Low NO_x"	Type of Firing
Georgia Power Co.	Harllee Branch	4	3	Horizontally Opposed
Utah Power & Light Co.	Naughton	3		Tangential
Arizona Public Service Co.	Four Corners	5	4	Horizontally Opposed
Alabama Power Co.	Barry	4	4	Tangential

FIGURE 4-4

CORROSION PROBE
DETAIL OF 2-1/2" IPS EXTENSION PIPE AND END PLATE
(OUTSIDE OF FURNACE)

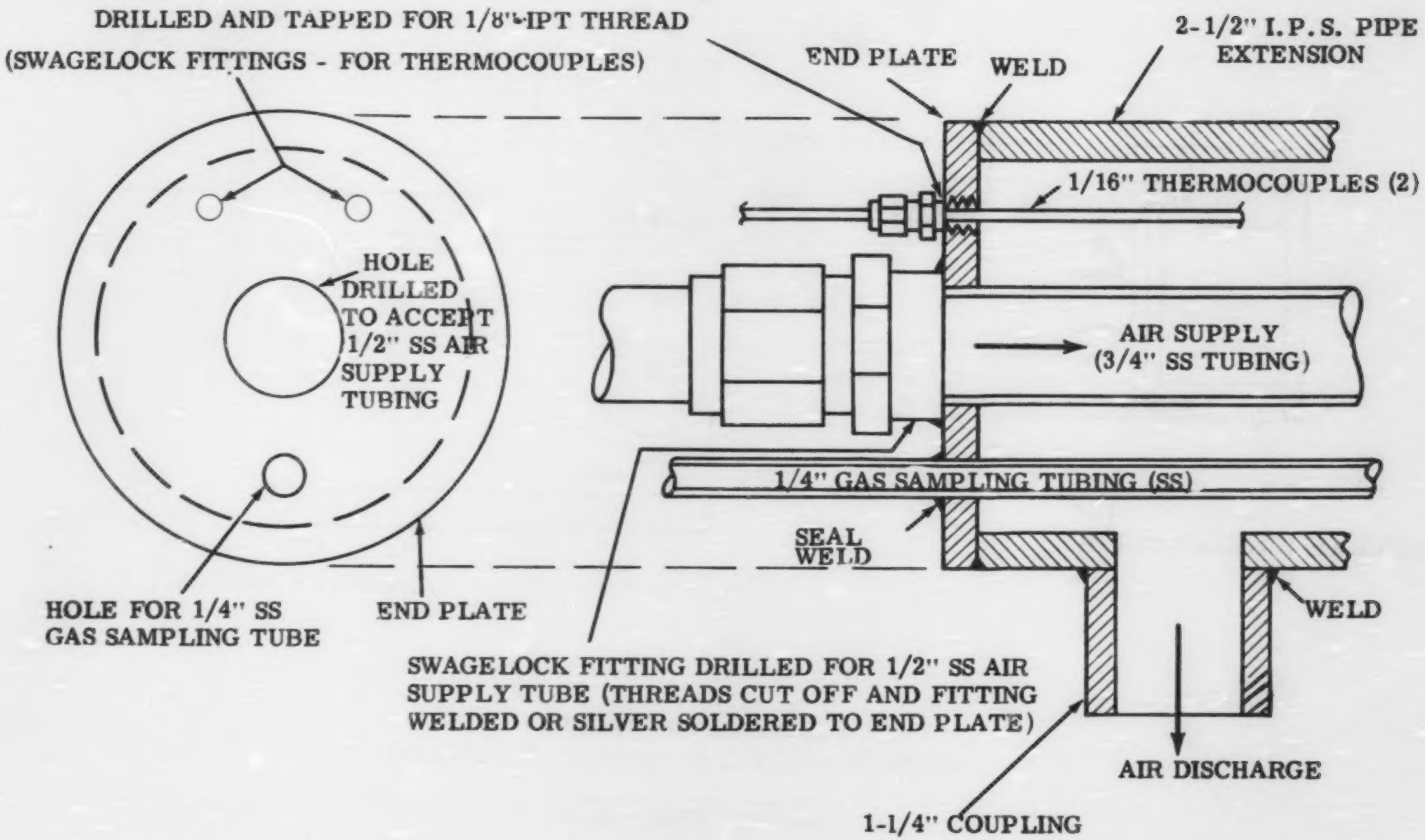
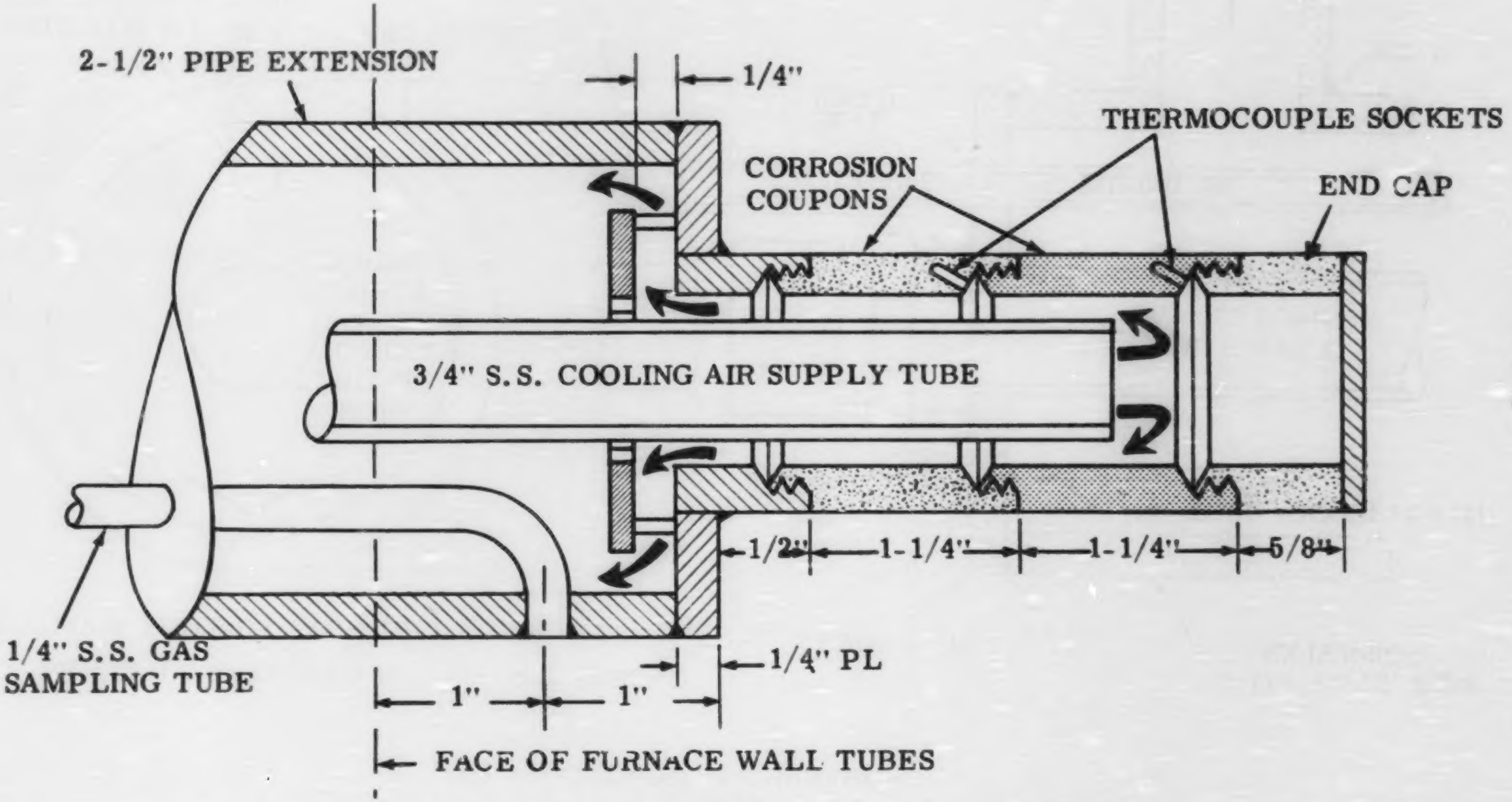

DRILLED AND TAPPED FOR 1/8"-IPT THREAD
(SWAGELOCK FITTINGS - FOR THERMOCOUPLES)
END PLATE
WELD
2-1/2" I.P.S. PIPE EXTENSION
1/16" THERMOCOUPLES (2)
HOLE DRILLED TO ACCEPT 1/2" SS AIR SUPPLY TUBING
AIR SUPPLY
(3/4" SS TUBING)
1/4" GAS SAMPLING TUBING (SS)
SEAL WELD
HOLE FOR 1/4" SS GAS SAMPLING TUBE
END PLATE
WELD
SWAGELOCK FITTING DRILLED FOR 1/2" SS AIR SUPPLY TUBE (THREADS CUT OFF AND FITTING WELDED OR SILVER SOLDERED TO END PLATE)
AIR DISCHARGE
1-1/4" COUPLING

FIGURE 4-5

CORROSION PROBE

DETAIL OF CORROSION COUPON ASSEMBLY
(INSIDE OF FURNACE)


2-1/2" PIPE EXTENSION
1/4"
THERMOCOUPLE SOCKETS
CORROSION COUPONS
END CAP
3/4" S.S. COOLING AIR SUPPLY TUBE
1/2"
1-1/4"
1-1/4"
5/8"
1/4" S.S. GAS SAMPLING TUBE
1/4" PL
1"
1"
FACE OF FURNACE WALL TUBES

5. COMBUSTION VARIABLES

Our Systematic Field Study of NO_x Emission Control Methods for Utility Boilers (1) was designed to explore the broad limits of short-term applicability of combustion modification on a representative sample of gas, oil and coal fired boilers. The major combustion operating variables explored were: (1) load reduction, (2) low excess air firing, (3) staged combustion, (4) flue gas recirculation, (5) air preheat temperature, (6) burner tilt, (7) auxiliary to coal air damper settings, and (8) secondary air register settings. In our current field test program, prime interest centered on coal fired boilers; first, to determine the optimum combination of combustion variables, as listed above, for NO_x emission reduction in short-period tests and second, to determine if slagging, corrosion or other operating problems were experienced in extended period tests under "low NO_x" operation. Other emissions (CO, hydrocarbons, and particulates) were also measured to determine whether they were adversely affected.

In this section, the major combustion variables investigated are discussed in general terms, while the details of the results obtained from each boiler tested are given in Section 6.

5.1 Load Reduction

Since load reduction is an economically unattractive method for reducing NO_x emissions, the major emphasis in this program was to determine the NO_x reduction capability of boilers at full or maximum possible load levels using combustion modifications for effective NO_x emission control. However, as shown by our overall correlations of gross load per furnace firing-wall and by the individual boiler results, reducing load in coal fired boilers generally reduced NO_x emissions by a lower percentage than the percentage reduction in load. Reduced load operation reduces the heat release per unit of furnace area or volume, lowers effective peak flame temperatures and thus lowers the thermal fixation of nitrogen in the furnace. In addition, low loads generally require operation at higher excess air levels than at full load and the increased availability of oxygen in the flame tends to increase NO_x emissions.

5.2 Low-Excess Air Firing

Low excess air firing is an effective method for NO_x emission control of coal fired boilers, alone and in combination with other combustion variables such as staged firing. This relationship is shown most clearly by expressing the excess air level as % stoichiometric air to active burners. Reducing excess air reduces NO formation, due to the lack of availability of oxygen, which preferentially combines with carbon, hydrogen and sulfur rather than nitrogen.

The minimum practical level of excess air that can be reached by each boiler depends upon a number of variables, such as load (lower loads require higher excess air levels), uniformity of air to fuel ratio for the operating burners, (greater uniformity permits lower excess air), slagging potential, furnace design (cyclone furnace requires relatively high excess air), burner tilt (lower excess air for down-tilt than for up tilt on tangentially fired boilers), secondary air register settings (closed-down registers allow lower excess air without violating minimum wind-box to furnace pressure differentials), steam temperature control flexibility, coal quality variation, and fuel and air control lags during load swings. With coal fired boilers, under ideal conditions, 4 to 5% excess air levels can be reached without exceeding 200 ppm CO emissions. More typical minimum excess air levels for coal firing in U.S. utility boilers are 8 to 12% while in some cases excess air levels below 15 to 18% present operating problems.

5.3 Staged Combustion

Staged combustion (with low excess air) has so far proven in short period tests to be the most effective method of combustion control for reducing nitrogen oxide emissions from coal fired boilers. Although coal fired boilers designed for two-stage combustion are just now coming on line, a modified type of two-stage combustion using some coal burners on air only has been successfully tested on a number of pulverized coal fired boilers (4). Staged combustion is effective in reducing both thermal and fuel NO_x emissions (8) due to limitation of oxygen and lower flame temperatures in the primary combustion zone, and lower effective temperatures in the secondary, air-rich combustion zone.

Both practical and theoretical considerations were involved in conducting staged combustion test runs. The lowest practical air-to-fuel ratios were applied to operating burners with maximum separation of "air only burners" from operating burners to provide for cooling between primary and secondary combustion zones. However, practical design and operating constraints often limited the modified staged combustion effectiveness for the following reasons:

- The number and location of burners that could be operated on an "air only" basis depends upon the pulverizer - burner configuration and the maximum increase of coal supply to active burners under full load conditions. Otherwise, modified staged combustion generally resulted in a reduction in load. Fortunately, some boilers do have the capacity to operate at full load with one or more pulverizers off, and thus have more staging flexibility.
- Some boilers do not have the capability of closing off individual coal burners from a pulverizer. Thus, all burners fed by a pulverizer are either on "active" or on "air only" operation.

- In some boilers, division wall tube temperature limitations, or suspected side wall corrosion problems prevent the use of ideal "air-only" burner patterns.
- Steam temperature control problems can also prevent the use of ideal burner patterns.
- Furnace slagging tendencies may prevent the use of optimum burner staging configuration. For example, attempts to minimize air-to-fuel ratios in the bottom levels of a tangentially fired boiler with down-tilt burners were not successful because of excessive slag build-up on bottom side-walls and slopes of the furnace.
- The option to decrease secondary air register openings on active burners to optimum settings while simultaneously operating with wide open settings on "air only" burners to achieve maximum NO_x emission reduction is not available on all boilers. Most boilers with cell-type burners (2 or 3 burners in one assembly) must operate all burners within each cell at a common register setting, even though one or two burners are operated with air only. In some boilers secondary air register settings are tied in with controls in such a manner that they can only be operated in completely open, or fully closed modes. Other boilers have fixed secondary air register settings. Many boilers have broken, non-operable register mechanical linkages or inaccurate register setting indicators.

5.4 Flue Gas Recirculation

Flue gas recirculation into the windbox or secondary air ducts of the furnace combustion has been shown to be an effective method of reducing NO_x emissions from gas and oil fired boilers (4-6). One boiler selected for this test program, in part because of its flue gas recirculation capability, unfortunately could not be operated in this mode because of fan blade erosion during our test period. Based on theoretical grounds (1) as well as on actual experience with pulverized coal fired test rigs (7), flue gas recirculation is expected to be effective primarily for reducing thermal NO_x, and affect fuel NO_x formation to a minor extent only, in coal-fired utility boilers.

5.5 Burner Tilt

Tangentially fired boilers are designed with tilting burners (plus or minus 30° from horizontal) for superheat steam temperature and combustion flexibility. Other generally available operating variables that can assist in steam temperature control are superheat and reheat attemperation water sprays, excess air level, pulverizer loading patterns, secondary air register settings and soot-blower operation. Thus, burner tilt can often be used (within limits) to reduce NO_x emission levels without losing adequate steam temperature control, although operators must be aware of potentially aggravated slag problems.

Raising burner tilts above the horizontal (on up fired boilers) tends to enlarge the effective furnace combustion zone, to lower combustion intensity, and lower effective high temperature residence time resulting in reduced NO_x emission levels for a given excess air level. Down-tilt tends to reduce the furnace combustion zone, increases combustion intensity, and increases effective high temperature residence time, resulting in increasing NO_x emissions levels for a given excess air level. The usefulness of burner tilt as a NO_x emission control variable is partly offset by the higher excess air levels generally necessary with up-tilt burner operation. This higher excess air is needed to allow for the greater flue gas stratification observed with up-tilt burner operation caused by shorter times for complete mixing and combustion prior to the flue gases reaching the furnace arch, and dividing into two streams. Of course, potential slagging problems, and less flexible steam temperature control systems also limit the usefulness of burner tilt for NO_x emission control. From a NO_x emission standpoint, firing with the burners in a horizontal or slightly upward tilt appears to give the best results.

5.6 Other Combustion Variables

The importance of secondary air register settings and its relationship to the use of other combustion variables have been discussed above in the low excess air and staged combustion sections. Lowering air preheat temperatures can lower thermal NO_x emission within rather narrow limits in existing boilers with major steam side redesign required for effecting large changes in air preheat temperatures. Pulverized coal fineness showed only a minor effect on NO_x emissions in the limited testing performed on this variable.

While it was recognized that other combustion variables such as burner design and configuration, coal nitrogen content, and primary to secondary air ratios could have an important effect on NO_x emission, systematic testing of these factors was beyond the scope of the present study.

Detailed results of the field test program are presented in the following sections of this report. It should be noted that the selection of combustion variables was guided by known theoretical considerations of the formation of NO_x in combustion processes. However, boiler design and practical operating limitations and restrictions determined the actual, detailed program plan for each boiler tested.

5.7 Combinations of Combustion Modifications

As discussed in considerable detail in earlier Esso studies on NO_x emission control (1-6), combinations of combustion modification techniques can be used effectively for this purpose. Undoubtedly, the most powerful of these combinations is the use of staged burner firing patterns in conjunction with low overall excess air for all fossil fuel types. This mode of operation results in the combustion of the bulk of the fuel under reducing conditions, which affects the formation of both "thermal" and "fuel" NO_x.

Flue gas recirculation into the burner zone is a technique that by itself suffers from the limitation for coal firing that it appears to have little effect on "fuel" NO_x (1, 7, 8), because its principal effect is to reduce the combustion temperature. Thus, the relatively temperature-insensitive oxidation of chemically bound nitrogen is not reduced significantly using this technique. These comments also apply to other means of reducing combustion temperature, such as steam or water injection, or reducing air preheat temperature. However, for applications where "trimming" of NO_x emissions already controlled through other techniques is desirable, the use of flue gas recirculation and steam or water injection should be kept in mind, as they are expected to have an additive effect on NO_x reduction in such cases. Furthermore, these techniques can be beneficial for improving boiler operability, e.g., steam temperature control. However, steam or water injection of large quantities of H_2O (on the order of 0.5:1 to 1:1 mass ratio to fuel fired) reduces boiler efficiency by 4-6%. For similar reasons of reduction in boiler efficiency, the use of reducing air preheat temperature is usually not felt to be attractive for utility boiler applications.

"Minor" combustion variables (from the standpoint of NO_x emission control) have to be adjusted and optimized for each individual boiler, based on the broad experience gained with different types of boilers having different sizes, and fired with the large variety of coal and other fuel types in the U.S.

6. FIELD TEST RESULTS

The field test results obtained on individual coal fired boilers under a variety of operating conditions are presented in four parts. These parts consist of gaseous emission measurements, flue gas particulate loadings measured upstream of particulate collector equipment, corrosion probing data obtained in accelerated furnace fire-side water-tube corrosion tests, and estimated boiler performance. Gaseous emission data and most of the particulate emission data were obtained under normal, as well as staged firing conditions. As discussed before, particulate loadings of the flue gas were determined only under conditions corresponding to baseline and "low NO_x" operation, for purposes of comparison on the relative effect of modified combustion operation on flue gas particulate loadings in coal combustion. Similar considerations apply to the sustained, 300-hour corrosion tests, which had as their objective the determination of whether staged firing of coal accelerates furnace water tube corrosion rates.

The gaseous emission data obtained under baseline and staged firing conditions at various load levels are presented first. Throughout this report, NO_x concentrations are expressed as ppm, adjusted to three per cent O_2 in the flue gas, on a dry basis.

In addition to the results obtained in tests coal fired boilers, this section also presents the gaseous emission data on oil-fired units converted from coal.

6.1 Coal Fired Boilers

Test programs were conducted on 12 coal fired boilers consisting of four front-wall fired, three opposed-wall fired, four tangentially fired and one turbo-furnace boiler. Typical cross-sectional diagrams for these types of boilers are shown in Appendix C. Table 6-1 lists each boiler by station and number, boiler manufacturer, type of firing, full load MW rating, number of burners and number of burner levels. In addition, the number of operating test variables included in each test program and the number of completed test runs are shown.

6.1.1 Gaseous Emission Results for Individual Coal Fired Boilers

The data obtained from the 12 boilers tested are grouped according to boiler design type, i.e., front-wall fired, opposed-wall fired, tangentially fired and turbo-furnace boilers.

6.1.1.1 Gaseous Emissions from Front Wall Fired Boilers

Boilers 1, 2, 3 and 4 are front-wall fired boilers varying in size from 105 to 320 MW. Dave Johnston No. 2 and Widows Creek No. 6 were designed by Babcock and Wilcox, while E. D. Edwards No. 2 was designed by

TABLE 6-1

SUMMARY OF COAL FIRED BOILERS TESTED

	Station and Boiler No.		Boiler MFG.	Type of Firing	MCR (MW)	No. of Burners	No. of Burner Levels	Test Variables	No. of Test Runs
1	Dave Johnston	2	B&W	FW	105	18	4	3	14
2	Widows Creek	6	B&W	FW	125	16	4	4	41
3	E. D. Edwards	2	R-S	FW	256	16	4	4	19
4	Crist	6	FW	FW	320	16	4	4	22
5	Leland Olds	1	B&W	HO	218	20	3	3	13
6	Harllee Branch	3	B&W	HO	480	40	4*	4	51
7	Four Corners	4	B&W	HO	800	53	6**	5	26
8	Barry	3	C-E	T	250	48	6	4	8
9	Naughton	3	C-E	T	330	20	5	6	26
10	Barry	4	C-E	T	350	20	5	7	46
11	Dave Johnston	4	FW	T	348	28	7	7	6
12	Big Bend	2	R-S	Turbo	350	24	1	4	14
									286

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* Two levels of burner cells with two burners per cell.

** Two levels of burner cells with three burners per cell.

Riley-Stoker, and Crist No. 6 was designed by Foster Wheeler. All four of these boilers have four levels of burners. Widows Creek No. 6 boiler will be discussed first since it was tested in most detail being the first boiler studied in this program.

6.1.1.1.1 Widows Creek, Boiler No. 6

Tennessee Valley Authority's Boiler No. 6 at the Widows Creek Station was the first boiler tested in our present study. Thirty-two short-term test runs were made in a statistically design optimization program, to minimize NO_x emissions. These tests were followed by two sustained runs, one at full load, the other one at reduced load, with the optimum staging patterns. The sustained corrosion probing run was deferred at TVA's request, until high sulfur coal could be fired, and other data become available to show that staged firing would not cause abnormally high furnace corrosion rates.

Widows Creek Unit No. 6 is a 125 MW, 16-burner, front-wall, pulverized coal fired Babcock and Wilcox boiler. It has a single dry-bottom furnace with a division wall, and the 16 burners are arranged with four burners in each of four rows. Each row is fed with coal by a separate pulverizer.

The statistical test design shown in Table 4-1 for this boiler has been discussed in Section 4.1.3. The detailed operating and emission data are listed in Table 1 of Appendix A. The NO_x emission data, expressed as ppm NO_x corrected to three per cent oxygen in the flue gas (dry basis) obtained with the various firing patterns tested are summarized in Figures 6-1 and 6-2. In Figure 6-1, the measured emissions are plotted vs. per cent of stoichiometric air to the active burners. Figure 6-2 shows the same emission data, but plotted as a function of the overall per cent stoichiometric air. Least squares regression lines have been fitted to the data points corresponding to various firing patterns designated as "S".

Actual baseline NO_x emissions (full load, normal firing with 60% open secondary air registers) averaged 634 ppm at 18% excess air. (For comparison purposes it should be noted that the baseline NO_x emission level at 120% stoichiometric air calculated from all normal firing, full load runs is equal to 666 ppm.) Each of the four operating variables included in the experimental plan, i.e., excess air level, load, firing pattern and secondary air register setting had a significant effect on NO_x emission levels, and are discussed in turn below.

Low excess air operations consistently reduced NO_x emission levels as shown by the least saqure regression lines plotted in Figures 6-1 and 6-2. A 10% reduction in stoichiometric air to active burners reduced NO_x emissions by 25% under full or reduced load, normal firing

FIGURE 6-1

PPM NO_x (3% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(WIDOWS CREEK, BOILER NO. 6)

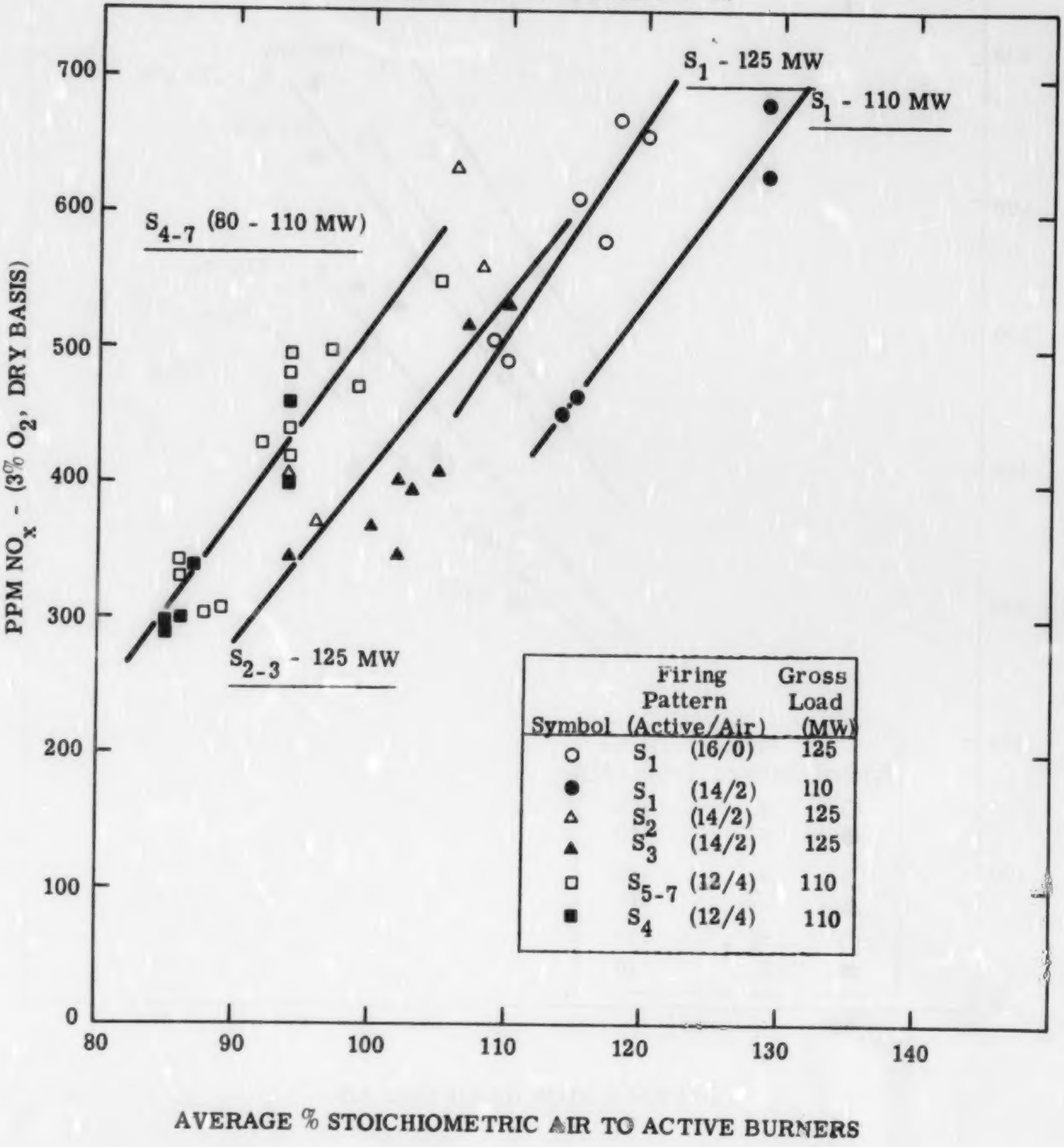
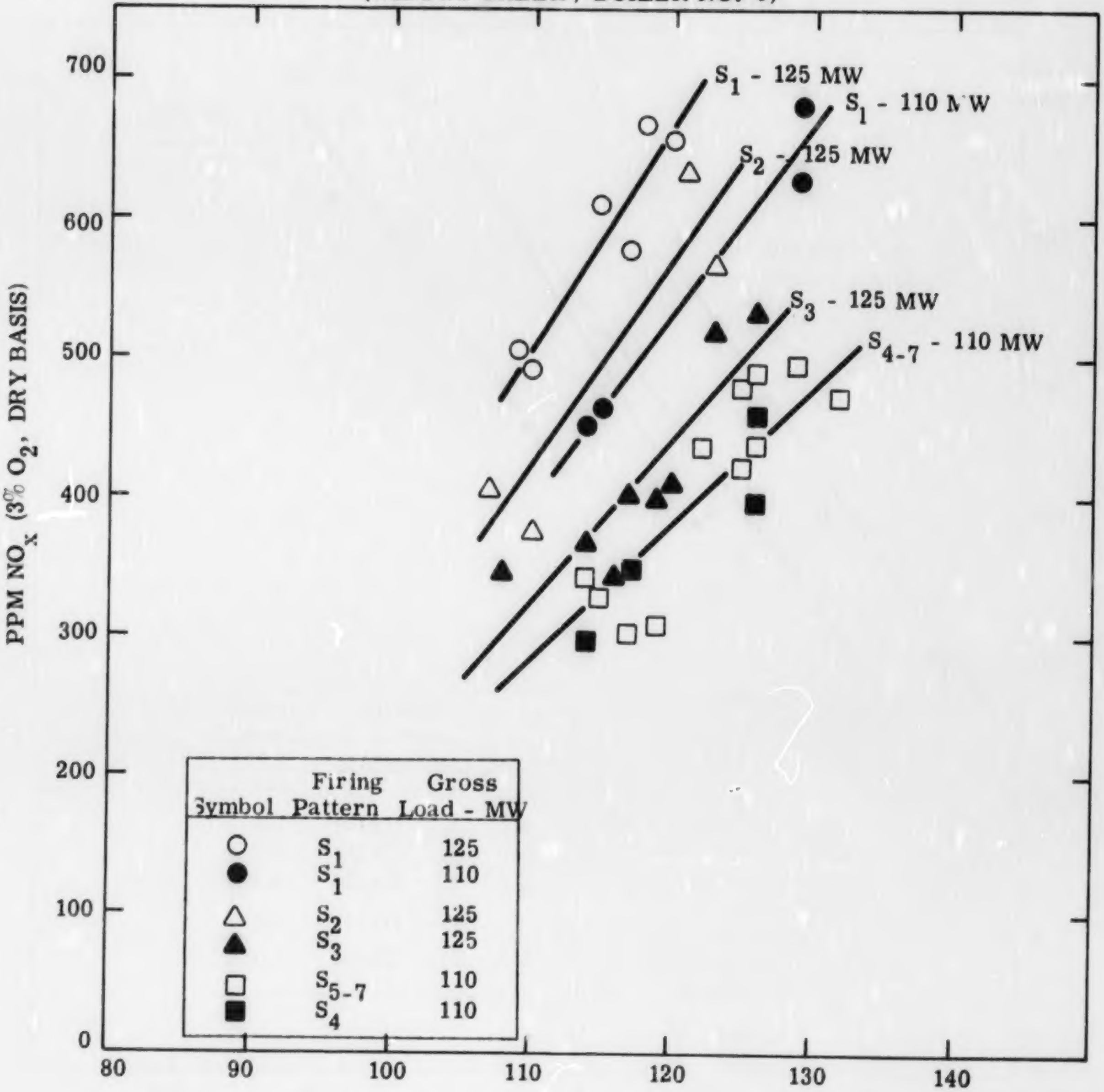


FIGURE 6-2

PPM NO_x (3% O_2, DRY) VS OVERALL STOICHIOMETRIC AIR

(WIDOWS CREEK, BOILER NO. 6)



% OVERALL STOICHIOMETRIC AIR

operation. The same percentage reduction in stoichmetric air under staged firing reduced NO_x emissions by an average of 24% at full load and 28% at reduced load. The lowest practical level of excess air was dictated by acceptable CO emissions and stack appearance.

Reducing load from 125 to 110 MW (12% reduction) with normal, 16 burner firing resulted in little change in NO_x emission levels since the average excess air level was raised during low load operation. However, when operating at equal excess air levels (say 20% overall excess air) a 12% reduction in load resulted in a 20% reduction in NO_x emission levels under normal firing as well as under staged firing conditions.

Staged firing had a statistically significant effect on NO_x emission levels under both full load (14% NO_x reduction) and reduced load operation (27% NO_x reduction). At full load, staging pattern S_3 (top row wing burners on air only) consistently produced lower NO_x emission levels than staging pattern S_2 (bottom row wing burners on air only) as shown by their least square regression lines of Figure 6-2. At reduced load, staging pattern S_4 (top row of burners on air only) resulted in the lowest NO_x emission levels. The combination of low excess air and staged firing reduced NO_x emissions by 40% at full load, and from 33 to 50% at reduced load. The optimum combination of operating variables reduced NO_x by 46% at full load and by 53% at reduced load compared to full load, baseline emission levels.

Opening the secondary air registers resulted in a small (5%) but statistically significant reduction in NO_x emissions when firing coal in all burners. When firing at full load with two burners on air only, no significant change in average NO_x emissions resulted from changing secondary air registers. However, closed down secondary air registers consistantly resulted in lower NO_x emissions (average of 14%) during staged firing operation with four burners on air only. This improvement can be explained by improved mixing of fuel and air with less CO formed as well as less air to active burners since a higher proportion of air will be diverted to the open top burners.

The data shown in Figure 6-1 call attention to an apparent anomaly. A cursory inspection of the data would indicate, that while as expected NO_x levels decrease with decreasing air supply to the active burners, staging the burners could result in higher NO_x emissions than normal operation at the same burner air/fuel ratio. A refined method for estimating the actual air/fuel ratio at each burner for each staged firing pattern can explain this anomaly. Since this method applies to other wall fired boilers, a specific example will be used here to briefly explain the method.

Staged firing pattern, S_4, (top row of 4 burners on air only and the bottom 3 rows firing coal) at 20% overall excess air results in an average % stoichiometric air to each of the 12 active burners of

90% i.e., air to coal = 120/16 to 100/12. (Since 120% air is divided among 16 burners while 100% of the coal is divided among the 12 active burners.) However, some of the air from the inactive top row of burners mixes with the partially unburned coal/air mixture from row B (less than 5 feet below) raising the actual % stoichiometric air ratio above the 90% for the bottom two rows (12 and 17 feet below). Based on visual observation of flame patterns during staged firing and simplified calculations it appears that a one-third mixing efficiency for the top row air with the coal-air mixture is a reasonable estimate. Table 6-3 presents the calculations to bring actual NO_x emission data in agreement with those calculated by extrapolating from unstaged levels.

Figure 6-3 presents the least squares regression lines calculated for the six test runs (shown as circles) made at full load with normal firing, as well as for the six test runs (shown as squares) made using staged firing pattern S_4. The actual ppm NO_x emissions for the six S_4 runs are also plotted (as hexagons) vs. the "effective" % stoichiometric air. Run No. 24 NO_x results fall 13% below their "expected" value due largely to the low load (89 MW vs. the 104 MW average of other five runs) for this run. It should also be noted that each of the "expected ppm NO_x" points plotted against the "effective" % stoichiometric air would fall on, or very close to the extrapolated S_1 regression line. Thus, we can estimate the maximum NO_x reduction if NO-ports were added to this boiler (at a sufficiently high elevation so that very little air would be mixed with the primary flame front). At 120% overall excess air S_1 produces 667 ppm NO_x, S_4 produces 370 ppm, while true 2-stage combustion would approach 222 ppm NO_x emissions.

6.1.1.1.2 Dave Johnston, Boiler No. 2

Boiler number 2 of the Dave Johnston Station of the Pacific Power and Light Company is a Babcock and Wilcox designed, front wall fired, single furnace boiler with a maximum continuous rating of 102 MW gross load. Six pulverizers feed 18 burners arranged in four rows with 3 burners in the top row and 5 burners in each of the other three rows. (Figure 6-4 shows the mill-burner configuration.) The 18 burners in this unit are of the circular register type which imparts a spinning action to the secondary air stream.

Detailed operating and emission data are summarized in Table 2 of Appendix A. Table 6-5 indicates the experimental design of operating variables with average flue gas measurements of % oxygen and ppm NO_x (3% O_2, dry basis) shown for each of the 14 runs completed on this boiler. Operating variables were firing pattern, secondary air register settings on coal mills not firing coal, and excess air level. Gross load was maintained near full load for all test runs due to a tight load demand during the test period. Number 12 mill feeding the

TABLE 6-3

CALCULATION OF EXPECTED NO_x EMISSIONS FROM % STOICHIOMETRIC AIR TO ACTIVE BURNERS

Burner Row	Coal %	Air %	A/C %	Expected NO_x, ppm (E)	Actual NO_x, ppm (A)	% Difference
				[2]	[3]	
A (Top)	0	28.5	120[1]	667		$100\left(\frac{A - E}{A}\right)$
B	33.33	30.5				
C	33.33	30.5	91.5	222		
D	33.33	30.5	91.5	222		
TOTAL	99.99	120[5]	100.7[4]	370	369	-0.3%

[1] Assumes 1/3 of air from Row A mixes with Row B.

[2] Calculated from S_1 Regression Equation: PPM NO_x = -1205 + 15.6 (% Stoichiometric Air).

[3] Calculated from S_4 Regression Euqation: PPM NO_x = -1026 + 15.5 (% Stoichiometric Air).

[4] Average "Effective" % Stoichiometric air to active burners.

[5] Assumes 5% primary air and 95% secondary air.

Similar calculations have been made for each run with staged firing pattern S_4. The results are listed in Table 6-4, and plotted in Figure 6-3.

TABLE 6-4

CALCULATION OF EXPECTED NO_x EMISSIONS FROM AVERAGE "EFFECTIVE" % STOICHIOMETRIC AIR TO ACTIVE BURNERS

Run No.	% Stoichiometric Air		"Effective"	Expected PPM NO_x	Actual PPM NO_x	% Diff. $100\left(\frac{A - E}{A}\right)$	Gross Load (MW)
	Overall	To Active Burners					
13	126	94	106	449	460	+3	110
20	116	87	98	319	345	+8	108
24	126	94	106	449	399	-13	89
26	114	86	96	297	297	+9	99
$26A_1$	115	86	97	308	299	-3	99
$26A_3$	113	85	95	277	290	+4	103

FIGURE 6-3

PPM NO_x (3% O_2, DRY BASIS) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS FOR S_1 AND S_4 RUNS

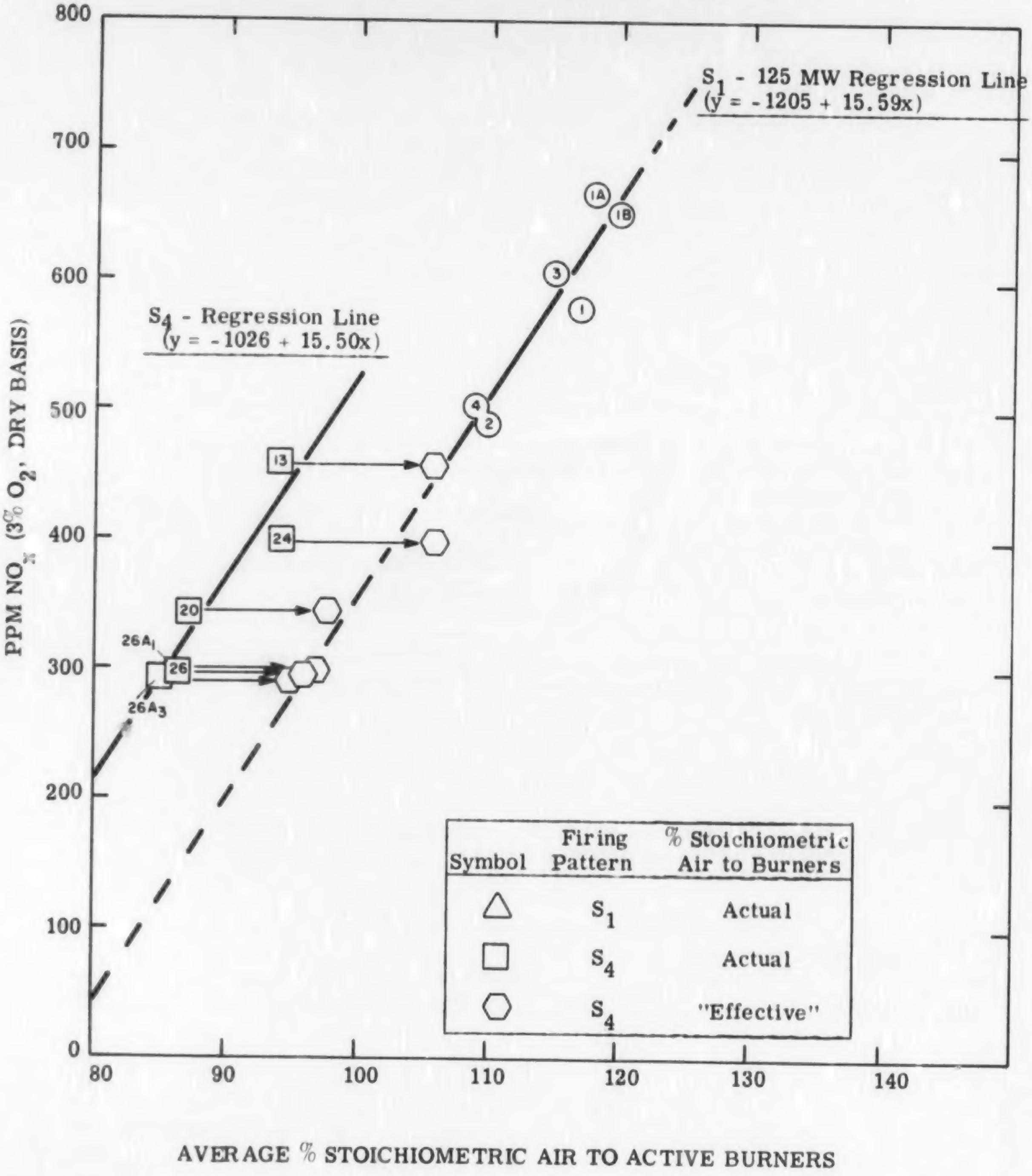


FIGURE 6-4

PPM NO_x (3% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(DAVE JOHNSTON, BOILER NO. 2)

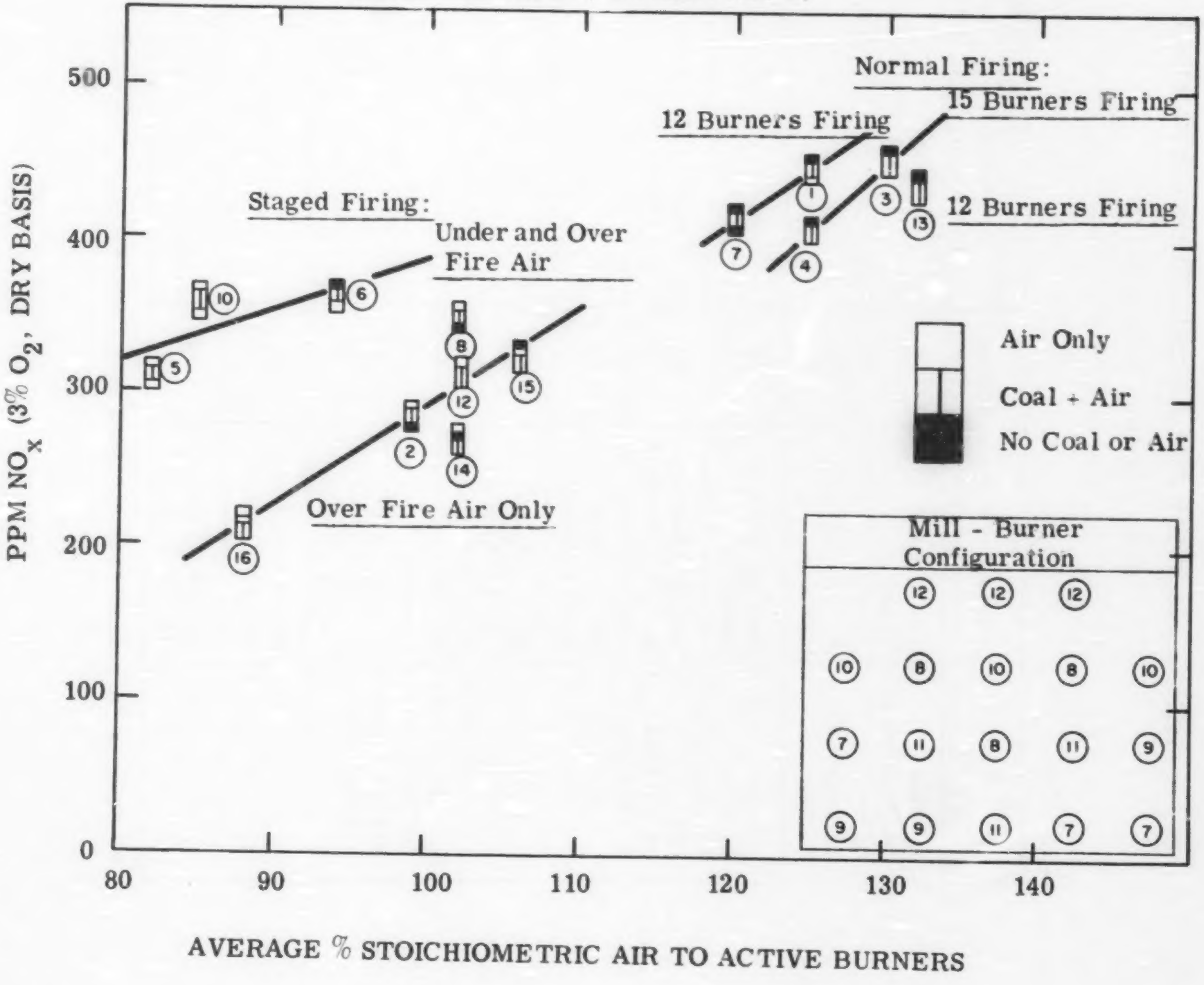


TABLE 6-5

EXPERIMENTAL DESIGN WITH % O_2 AND PPM NO_x (3% O_2 BASIS)

(Dave Johnston, Boiler No. 2)

			Load: 98 to 106 MW	
Firing Pattern	Secondary Air Registers	Staged Pattern	A_1-Normal Excess Air	A_2-Low Excess Air
F_1 - No. 12 Pulverizer Off 15 Burners Firing	No. 12 Pulv. Closed	S_1	(3)* 5.0% O_2 454 ppm NO_x	(4) 4.3 409
	No. 12 Pulv. Open	S_2	(11)	(12) 4.1 314
F_2 - No. 11 and 12 Pulverizers Off 12 Burners Firing Coal	Nos. 11 & 12 Closed	S_1	(1) 4.3 450	(7) 3.7 413
	No. 11 Closed No. 12 Wide Open	S_3	(8) 4.6 347	(2) 4.2 284
	No. 11 Open No. 12 Closed	S_4	(9)	(6) 3.3 362
	No. 11 Open No. 12 Open	S_5	(10) 4.6% 358	(5) 4.0 311
F_3 - No. 12 & 10 Pulverizers Off 12 Burners Firing Coal	No. 10 & 12 Closed	S_1	(13) 5.2% 438	
	No. 10 Closed No. 12 Open	S_6		(14) 4.7 270
	No. 10 Open No. 12 Closed	S_7		(15) 5.3 326
	No. 10 Open No. 12 Open	S_8		(16) 5.2 214

* Numbers in parentheses are test run numbers.

top row of burners was down during the entire test period due to mechanical problems. Special advantage was taken of the wide range of firing patterns available at full load by testing 10 different combinations of coal mills off, with open or closed secondary air registers.

Figure 6-4 is a plot of ppm NO_x vs average % stoichiometric air to the active burners. The data points have been plotted as symbols indicating visually the various firing patterns tested. Solid lines have been drawn through the data points with similar operation to show the strong influence of excess air level.

Five test runs were conducted at about full load without staged air admission, except the small amount going through the secondary air registers to cool the "off" burners. Runs 1 and 7 were operated with mills 11 and 12 off; run 3 and 4 were operated with number 12 mill off and run 12 was conducted with mills 10 and 12 off. NO_x emission levels (corrected for excess air level) were highest for runs 1 and 7, intermediate for runs 3 and 4 and lowest for run 13. These results are in agreement with past operating experience and theory. Runs 1 and 7 were conducted with only 12 active burners (therefore at a higher firing rate of coal per burner) compared to 15 active burners in runs 3 and 4. Of more importance, runs 1 and 7 had cooling air flowing through burners at a lower elevation, counter balancing the beneficial effect of adding cooling air through 3 top burners, and in run 13, cooling air was added through 6 top burners to aid in reducing NO_x emission levels. Actual full-load baseline, NO_x emissions were 454 ppm.

Seven different staged firing patterns were tested with very instructive results. The five staging patterns operated with secondary air admitted through top burners listed in the order of decreasing NO_x reduction efficiency were: S_8 top two mills on air only (214 ppm); S_6, top mill on air only, bottom mill off (284 ppm); S_2 top mill on air only (314 ppm); and S_7, top mill off with cooling air and next to top mill on air only (326 ppm). The two staging patterns with secondary air admitted through both top and bottom burners were: S_5, top and next to bottom mills on air only (311 ppm) and S_6, top mill off with cooling air only and next to bottom mill on air only (362). Table 6-6 lists these low excess air, staged runs with ppm NO_x, % O_2 and average % stoichiometric air to active burners (calculated and adjusted bases) to allow comparisons. These results clearly demonstrate the importance of maximizing secondary air admission through top burners, providing minimum % stoichiometric air to active burners and minimizing the additon of secondary air through inactive bottom burners. (In other words, "overfire" air staged operation is preferred to "underfire" air firing modes.)

Analysis of these results are greatly simplified (as shown by Figure 6-5) when the calculated average % stoichiometric air is made more realistic by adjusting directionally for the "cooling" air that enters the furnace through the "closed" secondary registers of burners of "off-mills". If the closed registers are within the top two burner rows

TABLE 6-6

SUMMARY OF LOW EXCESS AIR, STAGED TEST RUNS

Staged Firing Pattern Mills Off and Secondary Air Register Position	Run No.	NO_x PPM	O_2 %	% Stoichiometric Air To Active Burners Calculated	Adjusted
Overfire Air				[1]	[2]
S_8 - 12 Open, 10 Open	16	214	5.2	88	88
S_6 - 12 Open, 10 Closed	14	270	4.7	102	99
S_3 - 12 Open, 11 Closed	2	284	4.2	99	102
S_2 - 12 Open	12	314	4.1	102	102
S_7 - 12 Closed, 10 Open	15	326	5.3	106	103
Over & Under-Fire Air					
S_5 - 12 Open, 11 Open	5	311	4.0	82	82
S_6 - 12 Closed, 11 Open	6	362	3.3	94	91

[1] Calculated as: $$\frac{\%\ \text{Total Air X No. of Burners Firing Coal}}{\text{No. of Burners Firing Coal plus No. of Burners on Air Only}}$$

[2] Adjusted for estimated "cooling" air. Deduct 3% from calculated % stoichiometric air for overfire "cooling" air and/or add 3% for underfire "cooling" air.

("overfire" cooling air) the calculated % stoichiometric air is reduced by 3%. For underfire air (No. 11 mill off) the adjusted % stoichiometric air is obtained by adding 3% to the calculated % stoichiometric air. Figure 6-5 shows that all of the test run data are closely clustered around three least-squares regression lines: normal firing, 7 = -82 + 4.95x; and staged "overfire" air, y = -436 + 7.30x. Each of these three operating methods reveals a strong (64 to 88%) relationship of excess air level with ppm NO_x emissions after adjusting for "cooling" air. The displacement of the staged firing regression lines from the extrapolated normal firing line can be accounted for by the mixing of "overfire" (or "underfire" air) into the burning air cool mixture from the next level of burners as shown for the Widows Creek No. 6 boiler. For example, the average "effective" stoichiometric air levels in test runs No. 5 and 12 are 107.4% and 107.3%, respectively, which produce expected NO_x emission of 317 ppm (from normal firing equation: y = -422 + 7.07x) compared to actual emissions of 311 and 314 ppm, respectively.

To summarize the results from this boiler, emphasis was placed upon the use of a wide variety of full load, staged firing combinations. From baseline NO_x emissions of 454 ppm, low excess air, staged operation reduced NO_x to as low as 216 ppm with a slightly darkened stack plume. Other staged firing patterns resulted in 275 to 320 ppm NO_x with no degradation of the plume. Excess air levels showed a strong influence on NO_x emission levels in general agreement with previous experience on wall fired boilers.

6.1.1.1.3 E. D. Edwards, Boiler No. 2

Boiler No. 2 at the E. D. Edwards station is a Riley Stoker Corporation, front-wall fired, pressurized, single furnace boiler. It was designed for a maximum continuous rating of 1,870,000 pounds of steam per hour with a superheater steam outlet pressure of 2600 psig at 1005°F. The furnace is fired with 16 burners (4 rows of 4 burners) and has dimension of 46 feet width, 30 feet depth, a furnace volume of 155,600 cubic feet and a furnace envelop of 37,700 square feet effective projected radiant surface.

A summary of the operating and emission data for each test run is contained in Table 3 of Appendix A. Table 6-7 below indicates the experimental design of operating variables with average flue gas measurements of % O_2 and ppm NOx (3% O2, dry basis) shown for each short-period test run. Almost all of the planned test runs shown were completed. Runs 21 and 22, peak load runs, could not be achieved during the hot summer testing period. Two special, long-period fluctuating load (load determined by industrial demand) runs were made under the operating conditions specified for runs 7 and 9. These runs, identified as 7A and 9A, were conducted in order to determine how NO_x emissions produced during varying load conditions would compare with the emission data obtained under steady-state short-period test runs. The analysis of the short-period test run results will be discussed first, followed by that of results from the two special runs.

FIGURE 6-5

PPM NO_x (3% O_2, DRY) VS ADJUSTED* AVERAGE % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(DAVE JOHNSTON, BOILER NO. 2)

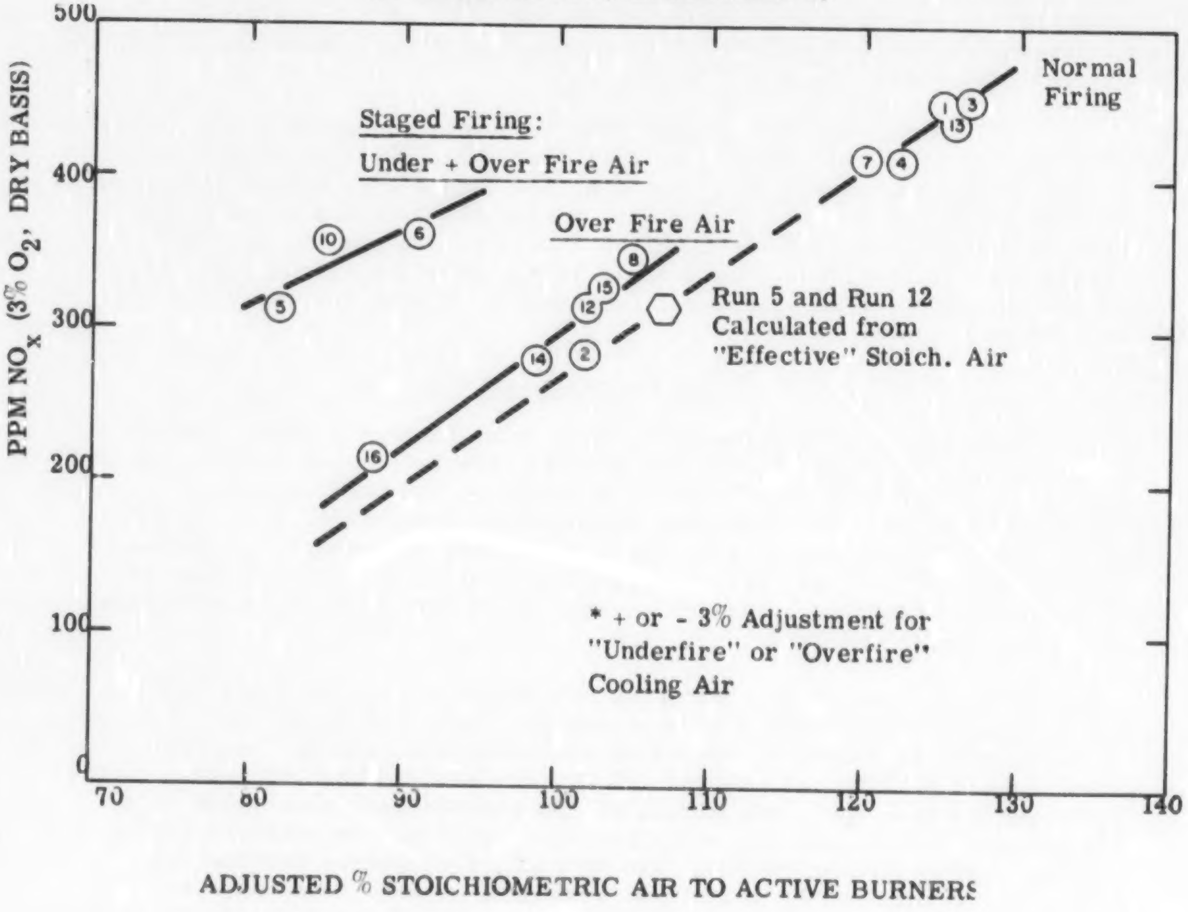


TABLE 6-7

EXPERIMENTAL DESIGN WITH PPM NO_x (3% O_2 BASIS) AND % O_2

(E. D. Edwards, Boiler No. 2)

Burner Firing Pattern	Secondary Air Register Setting	L_1-280 MW		L_2-260 MW		L_3-220-240 MW		L_4-210 MW	
		A_1-Nor. Air	A_2-Low Air	A_1-Nor. Air	A_2-Low Air	A_1-Nor. Air	A_2-Low Air	A_1-Nor. Air	A_2-Low Excess Air
S_1- Normal Firing Pattern	R_1 - 50% Open	(21)	(22)	(1) 670 3.2% O_2	(2) 556 1.5% O_2			(23) 667 4.2% O_2	(24) 516 1.6% O_2
	R_2 - 20% Open			(3) 770 3.1% O_2	(4) 692 1.8% O_2				
S_2 - A00A 0000 0000 0000	R_1 - 50% Open			(5) 644 3.8% O_2	(10) 474 2.0% O_2				
	R_2 - 20% Open			(9) 625 *3.9% O_2	(6) 359 1.6% O_2				
S_3 - 0AA0 0000 0000 0000	R_1 - 50% Open			(11) 609 3.8% O_2	(8) 524 2.7% O_2				
	R_2 - 20% Open			(7) 401 7.5% O_2	(12) 382 *2.1% O_2				
S_4 - AAAA 0000 0000 0000	R_1 - 50% Open					(13) 535 4.9% O_2	(18) 386 3.5% O_2		
	R_2 - 30% Open					(17)	(14) 310 4.4% O_2		
S_5 - A00A 0AA0 0000 0000	R_1 - 50% Open					(19)	(16) 336 2.8% O_2		
	R_2 - 30%					(15)	(20) 295 3.0% O_2		

* Secondary air registers 30% Open.

Table 3 Appendix A contains a summary of operating and emission data for the 20 short-period test runs completed on this boiler. Operating variables were gross load, excess air level, firing pattern and secondary air register setting. The maximum gross load tested was 256 MW (vs full load of 260 MW) with normal and staged firing, while the minimum load tested was 204 MW using a normal firing pattern. Excess air levels were set at normal operating levels or at the minimum level as established by maximum acceptable CO measurements in the flue gas. Five firing patterns were tested; normal firing with all 16 burners in operation, two staged firing patterns with two burners on air only, and two staged firing patterns with 4 burners on air only. Secondary air registers were set normally (45-50% open) or closed down to a 20 or 30% open position.

Each of the four operating variables showed a significant independent effect on NO_x emission rates and some significant two variable interaction effects were also apparent. Figure 6-6, a plot of average ppm NO_x vs % stoichiometric air to active burners (all short period test runs) has been prepared to show the relationship between NO_x emissions and excess air levels for various load, staged firing, and secondary air register setting test conditions.

Full load, baseline NO_x emissions were 703 ppm. Reducing load to 212 MW (16% reduction) resulted in a NO_x emission reduction of 5% (to 668 ppm).

Reducing excess air levels while holding other variables constant consistently resulted in lowering NO_x emissions, as shown by the least squares regression lines drawn through data points representing similar types of operation in Figure 6-6. The change in ppm NO_x emission with a 10% stoichiometric air reduction varied between 130 and 200 ppm and agrees well with other wall type boilers tested.

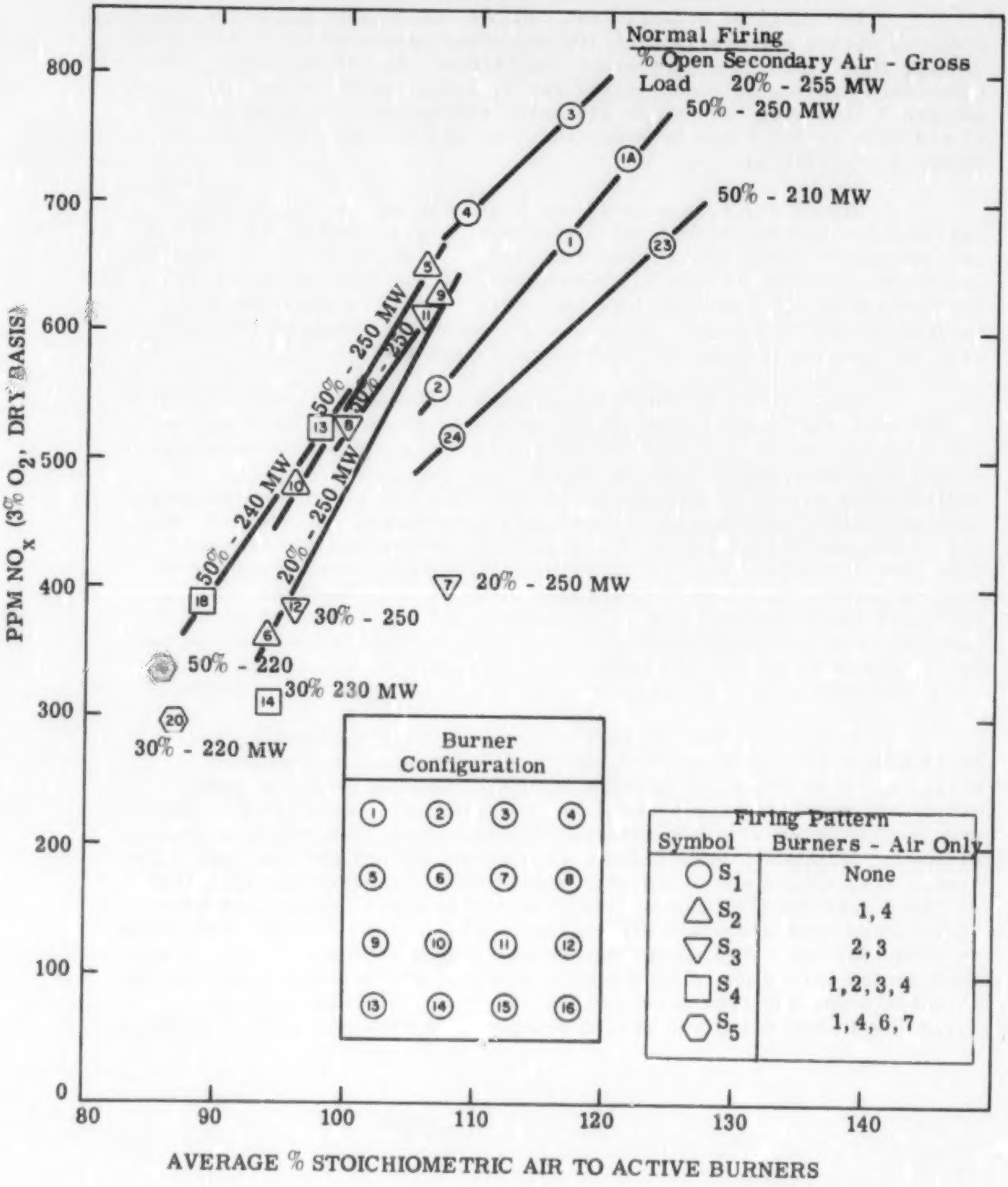
Secondary air register settings also showed a strong influence on NO_x emission levels. During normal firing of all burners, closing down dampers (20% open instead of 50%) increased NO_x emissions by 116 ppm (664 to 780) or about 17% when firing with 3% O_2 in the flue gas. This increase in NO_x emissions is to be expected due to the greater turbulance and higher peak flame temperatures associated with increased secondary air velocity at the burner. However during staged operation, closed down dampers consistently produced lower NO_x emissions than operation with normal damper positions. With closed down dampers during staged firing it was generally possible to reduce excess air levels to a lower level without exceeding the maximum permissible CO levels, and thus, lower NO_x levels were reached with this type of operation. Another explanation for this phenomenon is that a lower percent of stoichiometric air is introduced to the fuel rich burners when the air registers are pinched to 20-30% open because the flow restriction upsets the balance to each burner. Therefore a boiler operating at 0.9 stoichiometric ratio with all registers at 50% open may actually reach 0.85% stoichiometric ratio when the registers are closed to 20% open.

Staged firing operation resulted in lowered NO_x emissions, and as previously experienced, the combination of low excess air and staged firing showed further improvement. The average ppm NO_x emissions for the four test runs each with normal firing, staged firing S_2, and

FIGURE 6-6

PPM NO_x (3% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(E. D. EDWARDS, BOILER NO. 2, FIRING COAL)



staged firing S_3, were 670, 526, and 479, respectively, indicating an average emission of reduction of 22% using S_2 (top wing burners off) and 29% using S_3 (top middle burners off) compared to normal firing conditions.

As mentioned before, test runs 9A and 7A were conducted in order to obtain a comparison of NO_x emissions levels under normal, load varying conditions to steady state conditions. Run 9A operating conditions were similar to steady state run 9, i.e., normal excess air, staged pattern 2 (top wing burners on air only) and secondary air registers closed down to 30% open; however, the load was allowed to follow its normal industrial pattern.

Figure 6-7 is a plot of ppm NO_x emissions vs % O_2 measured in the flue gas for individual measurements of probe 2 and 3, or 1 and 4 gas composites taken during test run 9A. Also shown is the average NO_x and O_2 measurements of run 9. During most of the four and one-half hour period of this run the load was steady at 255 MW with two short periods at 230 to 235 MW. Thus, the NO_x emissions compared very well with the results of test run 9 obtained 7 days earlier.

Test run 7A operating conditions were similar those of run 7, except that the secondary registers were only closed to 30% open (vs 20% open for run 7) and in addition the load was allowed to vary with industrial load demand from 200 to 260 MW. Figure 6-8 is a plot of individual NOx vs O_2 measurements for run 7A. For comparison purposes, average results obtained under similar staged firing pattern 3 (middle top row burners on air only) are also shown as circled run numbers. This plot indicates that the variation of NO_x emissions during run 9A were largely (77%) related to changes in excess air level as shown by the solid least-squares line. Test runs 8 and 11, (operated with 50% open secondary air registers) are above the regression line, while test run 7 operated with 20% open secondary registers is considerably below the regression line indicating the importance of register settings.

To sum up, four operating variables were included in the experimental test program of 20 short-period test runs completed on boiler No. 2 at the E. D. Edwards Station. Changes in gross load, excess air level, firing pattern and secondary air registers produced significant changes in NOx emission levels. Base line emission levels of about 703 ppm NO_x were reduced to between 360 and 380 ppm under low excess air, staged operation with closed down secondary air registers at about full load. Reduced load, low excess air - staged operation with closed down secondary air registers resulted in further reductions to about 300 ppm. Two normal excess air staged firing runs with gross load varied according to load demand produced NOx emission levels close to those predicted from steady-state test runs, with most of the variation in NO_x emissions due to changes in excess air level variation.

FIGURE 6-7

PPM NO_x (3% O_2 BASIS) VS % OXYGEN IN FLUE GAS
(RUN 9A, E. D. EDWARDS, BOILER NO. 2)

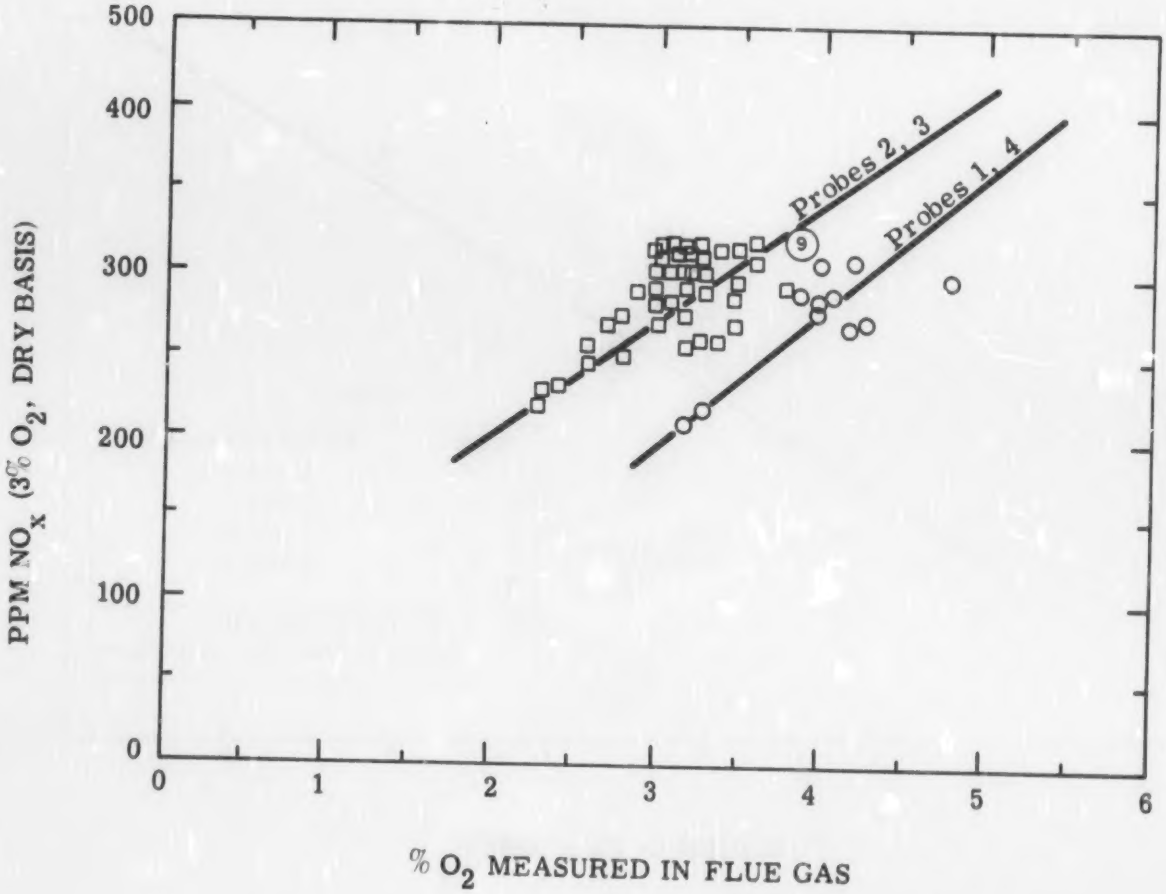
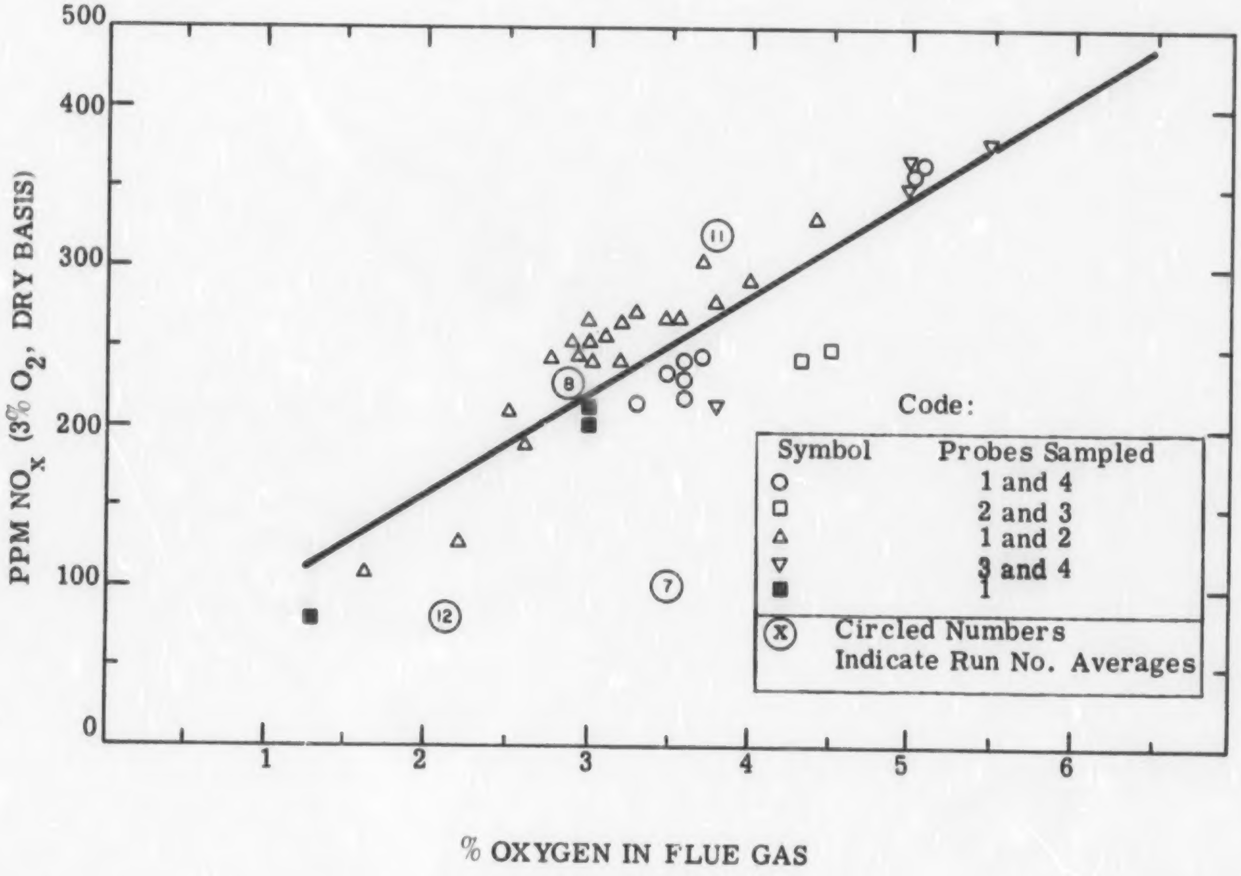


FIGURE 6-8

PPM NO_X VS % OXYGEN IN FLUE GAS (RUN 7A, E. D. EDWARDS, BOILER NO. 2)



6.1.1.1.4 Crist Station, Boiler No. 6

Crist Station Boiler number 6 is a Foster Wheeler designed, front wall fired single furnace boiler, with a maximum continuous rating of 320 MW gross load. The pressurized furnace has 16 burners arranged in four rows of four burners each. Superheat and reheat steam temperatures are 1000°F at pressures of 2484 psi and 569 psi respectively during full load operation.

A cooperative test program by Gulf Power, Foster Wheeler and Exxon, coordinated by EPA, was planned for this unit. Plans included short-term firing pattern optimization runs for minimizing NO_x emission, accompanied by boiler performance tests by Foster Wheeler, followed by boiler operability check-out at "low NO_x", then a sustained 300-hour test under "low NOx" and baseline operating conditions for assessing corrosion problems, and an optional long-term test period of about 6 months for determining actual furnace water tube wastage. Because of load demands on this boiler, however, it has been possible only to explore firing patterns in short-term runs only for minimizing NO_x.

Table 4 of Appendix A contains a summary of the operating and emission data subdivided into the "A" and "B" sides of the boiler. The flue gas stream leaving the furnace is split into two ducting paths, and although the boiler operator and manufacturer could at times achieve O_2 balance in the two sides, the NO_x levels measured were clearly higher for the "A" side than the "B" side, with all firing patterns tested. The reason for this difference is not completely understood at present, although it may be related to differences in air flow, and uncertainties of the air damper settings on the two sides of the boiler.*

To simplify the presentation and to facilitate comparison with other boilers, Figure 6-9 is based on the average of duct A and duct B results. Table 6-8 presents the experimental design with % oxygen and ppm NO_x for each test run on duct A, duct B and the boiler average. Operating variables tested were load, excess air level and firing patterns.

Reducing load from 320 to 270 MW (16% reduction) resulted in lowering NO_x from 845 to 794 ppm (6% reduction) for normal firing operation. Reducing excess air levels had a significant effect on NO_x emission levels under both normal and staged combustion operation as shown by the least squares regression lines of Figure 6-9. Staged firing also resulted in significant reduction in NO_x from the 832 ppm experienced during baseline, full load operation. The 320 MW staging pattern S_3 (middle top row burners

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* Foster Wheeler has indicated a possible cause of the side to side differences as attributable to three burner-register assemblies which were replaced on the "A" side prior to the test series. These registers have a different register assembly which might have resulted in different air flow characteristics.

FIGURE 6-9

PPM NO_x (3% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(CRIST, BOILER NO. 6)

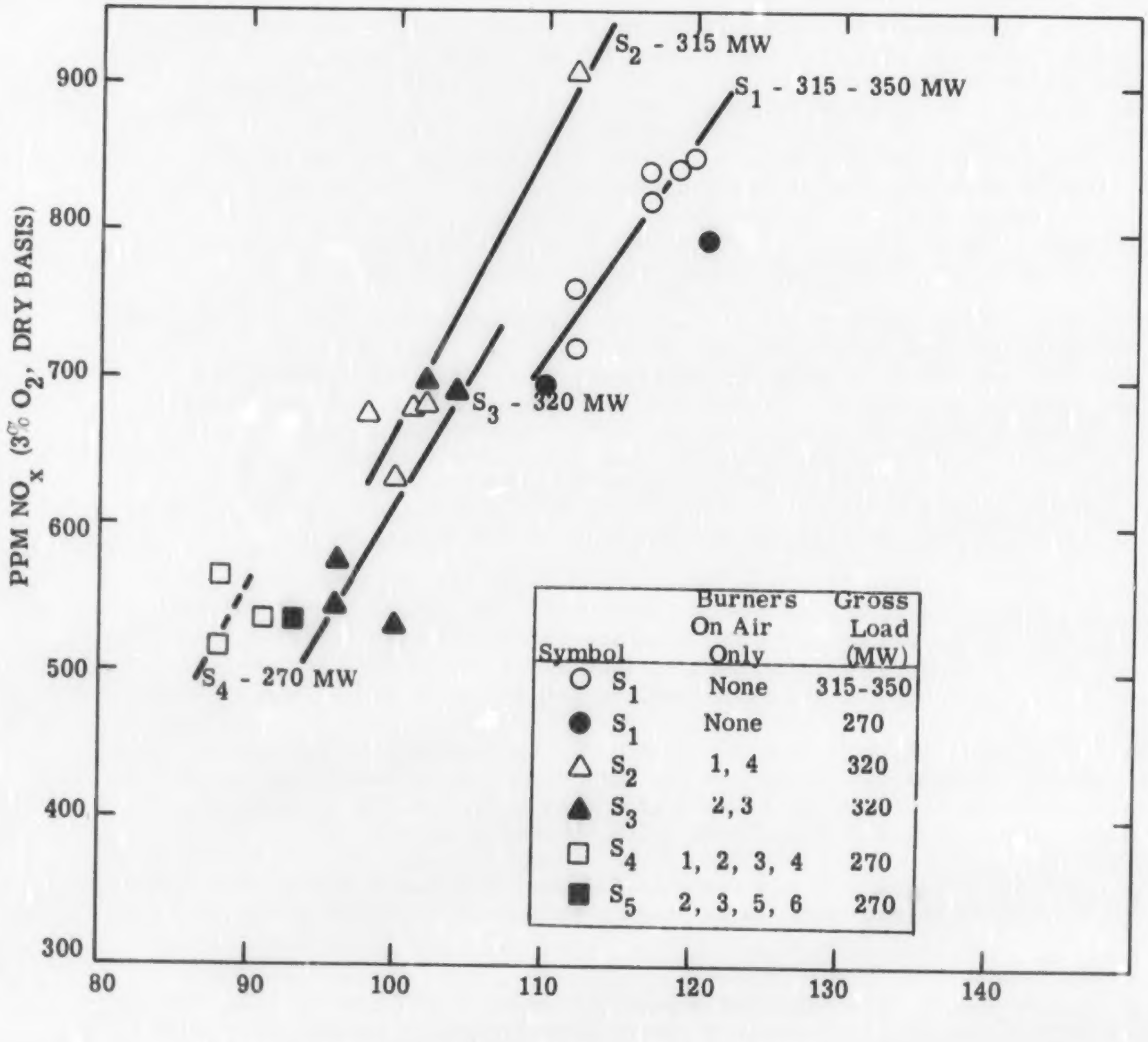


TABLE 6-8

TEST PROGRAM EXPERIMENTAL DESIGN - CRIST, BOILER NO. 6

(Run No., Average % Oxygen and PPM NO_x (3% O_2, Dry Basis) Measured in Flue Gas)

		L_1-350 MW	L_2 - 315 - 320 MW						L_3 - 270 MW			
		A_1-Nor. Exc Air	A_1-Normal Excess Air			A_2-Low Excess Air			A_1-Nor. Exc Air	A_2-Low Excess Air		
Sec. Air Reg.	Firing Patt	S_1-	S_1-	S_2-	S_3-	S_1-	S_2-	S_3-	S_1-	S_1-	S_4-	S_5-
Operating	Idle											
70% Open	0% Open	(26) 3.4-898 2.9-743 3.2-820 (26B) 3.2-888 3.5-801 3.4-844	(1) 3.6-902 3.6-799 3.6-850 (1R) 3.4-916 3.0-765 3.2-840			(6) 2.4-804 2.4-630 2.4-717 (6R) 2.6-862 2.1-660 2.4-761			(11R) 3.7-840 3.9-748 3.8-794	(14R) 2.0-754 2.2-640 2.1-697	(15A) 2.6-643 2.3-416 3.0-530	
	70% Open			(2) 4.7-946 4.7-872 4.7-909 (3) 2.3-724 3.4-631 2.8-678	(5A) 3.1-728 3.6-657 3.4-692		(7) 2.0-788 2.6-565 2.3-676 (8) 1.9-772 4.5-591 3.2-682 (8R) 3.1-738 2.2-526 2.6-632	(4) 1.4-516 4.0-546 2.7-531 (5) 0.9-532 3.2-620 2.0-576 (10) 1.8-566 2.2-522 2.0-544 (10R) 3.5-802 3.0-593 3.2-698			(16) 3.8-661 3.7-411 3.8-536 (16R) 1.8-560 4.5-472 3.2-516	(25R) 3.1-647 3.1-484 3.1-566

Code for Data in Cells (26) - Test Run Number
3.4% O_2 - 898 ppm NO_x - A Duct
2.9% O_2 - 743 ppm NO_x - B Duct
3.2% O_2 - 820 ppm NO_x - Average

on air only) produced better results (reduction to 526 ppm NO_x) than staging pattern S_2 (outside top row burners on air only). With the further reduced load of 270 MW, staging pattern S_4 (top row of burner on air only) produced lower NO_x results than staging pattern S_5 (top row wing burners and next to top row middle burners on air only).

It is hoped that eventually an opportunity may arise for completing the planned program on this unit.

6.1.1.2 Gaseous Emissions from Horizontally Opposed Coal Fired Boilers

Three Babcock and Wilcox designed opposed firing boilers were tested in this program: Leland Olds No. 1, 216 MW; Harllee Branch Number 3, 480 MW; and Four Corners No. 4, 800 MW full load rating. Since the Harllee Branch boiler was tested first and most extensively, it will be discussed first, followed by the Four Corners and Leland Olds boilers.

6.1.1.2.1 Harllee Branch, Boiler No. 3

Harllee Branch unit No. 3 with a full load rated capacity of 480 MW gross load, is a single furnace, pulverized coal fired Babcock and Wilcox boiler. It has 40 burners arranged in twenty burner cells of two burners each, with two rows of five burner cells located in both the front and rear walls of the furnace. The burner configuration and pulverizer layout are shown in Figure 6-10.

Table 5 of Appendix A provides a summary of the operating and emission data from each of the 51 test runs completed on this boiler. Operating variables included in the test program were load, excess air level, secondary air register setting and staged firing pattern.

Figure 6-11 contains individual data points and least squares, regression lines for the NOx vs. average % stoichiometric air to active burners for normal and staged firing.

Baseline NO_x emission levels at full load averaged about 711 ppm. Lowering the level of excess air was possible both under normal and staged operating conditions down to flue gas O_2 concentrations of about 1.5% or even lower, without apparent undesirable side effects. The steep effect of reducing the per cent of stoichiometric air to the active burners on decreasing NO_x emissions is shown by the least squares regressions of the data in Figure 6-11. A 10% reduction in excess air reduced NO_x emissions by about 100 ppm under normal firing, and by 118 ppm under staged firing conditions.

Interestingly, by operating four to six top burner cell row burners on air only, it was possible to maintain boiler load at 480 MW, and reduce the NO_x emission levels to about 488 ppm. This level corresponds to a reduction in NO_x of about one-third, compared with the baseline level. Usually, wing burners of the top rows of front and rear walls were operated on air only, but the NO_x emission levels were not particularly sensitive to the exact location of the inactive burners in the top row. Twenty different firing patterns were tested.

FIGURE 6-10

HARLLEE BRANCH, BOILER NO. 3
PULVERIZER AND COAL PIPE LAYOUT

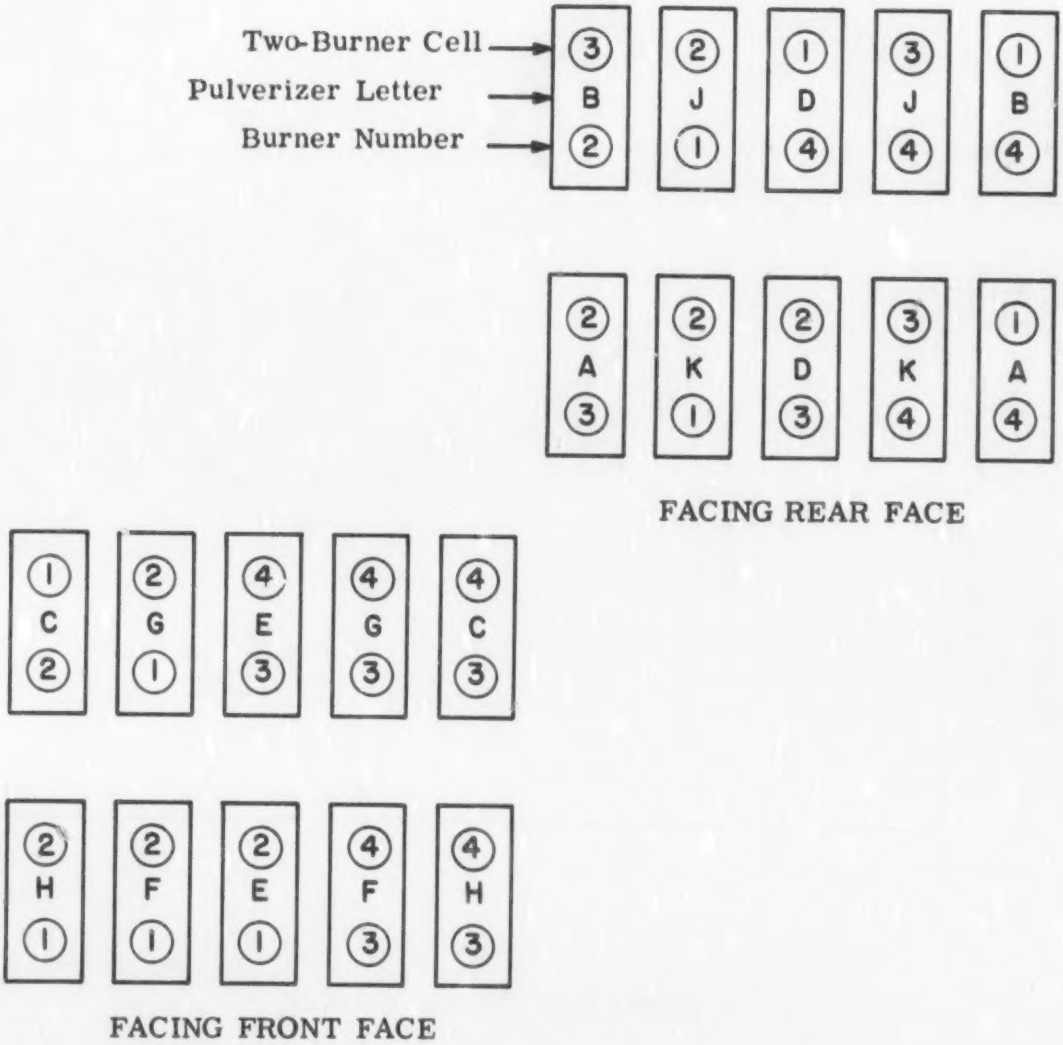
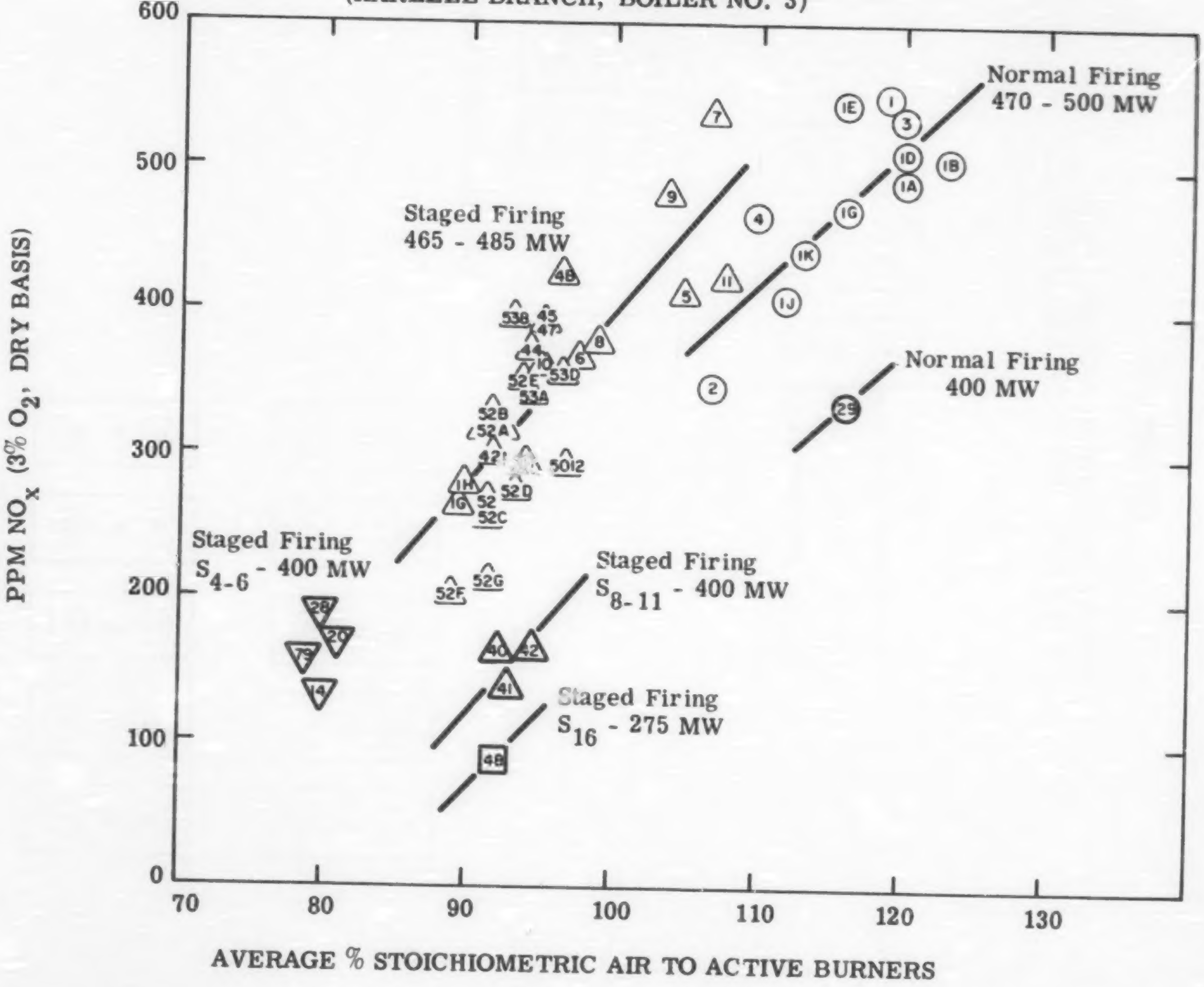

Two-Burner Cell
Pulverizer Letter
Burner Number
③ B ②
② J ①
① D ④
③ J ④
① B ④
② A ③
② K ①
② D ③
③ K ④
① A ④
FACING REAR FACE
① C ②
② G ①
④ E ③
④ G ③
④ C ③
② H ①
② F ①
② E ①
④ F ③
④ H ③
FACING FRONT FACE

FIGURE 6-11

PPM NO_x (3% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(HARLLEE BRANCH, BOILER NO. 3)



With only 30 active burners, i.e., 10 top row burners on air only, it was possible to reduce NOx emissions to about 354 ppm at low levels of excess air, or a reduction of over 50% from the baseline level. However, load was also reduced by 17% from 480 MW to 400 MW using this staging pattern.

Secondary air register setting had only a small effect on NOx emission levels. Wide open registers produced lower NO_x than the 50% open position under normal firing, while there were no significant differences observed **during** staged firing operation.

Reducing gross load from 480 MW to 400 MW (17% reduction in load) resulted in 672 ppm vs. 537 ppm NO_x (20% reduction in NO_x) at the same excess air level under normal firing conditions. As discussed above, larger reductions in NO_x emissions resulted from staged firing with low excess air.

6.1.1.2.2 Leland Olds, Boiler No. 1

Leland Olds unit number 1 has a full load rated capacity of 216 MW gross load. At the time of its first operation in 1966, it was the largest lignite fueled boiler in the Western Hemisphere. This Babcock and Wilcox designed boiler has a single furnace with opposed wall firing. Ten pulverizers feed 20 burners, arranged in three rows of four burners each in the front wall, and two rows of 4 burners each in the rear wall.

Table 6 of Appendix A contains a summary of the operating and emission data obtained from the 13 test runs completed on this boiler. Table 6-9 presents the experimental design with run number, % oxygen and ppm NO_x shown for each test run. Operating variables tested were gross load, excess air level and firing pattern.

Figure 6-12 shows a plot of ppm NO_x vs. average % stoichiometric air to the active burners. Full load baseline NO_x emissions were 569 ppm. The least squares regression lines indicate the strong influence of excess air on NO_x emission levels for both normal firing and staged firing. With normal firing of all burners, low excess air operation reduced NO_x emissions by 21% to 447 ppm. Low excess air, staged firing at full load (one mill on air only) reduced NO_x emission by as much as 34% to 375 ppm. Low excess air, staged firing at 15% reduced load (two mills on air only) reduced NO_x emissions by 54% to 260 ppm using the most effective staged firing pattern, S4 (top row front wall burners on air only).

The lignite coal fired at this station has a moisture content of around 34 to 39 percent (Appendix B, Table 9). It was expected that the high moisture would have a significant effect on baseline NO_x emissions. However, this boiler also has an abnormally high air preheat temperature 100 to 150°F higher than normal designs thought to be necessary for proper coal pulverization. The potential effect of the high coal moisture content apparently was cancelled out in our tests by the high air preheat temperature. Future lignite fired boilers would not require abnormally high air preheat temperatures and NO_x emissions, accordingly, would be expected to be significantly lower.

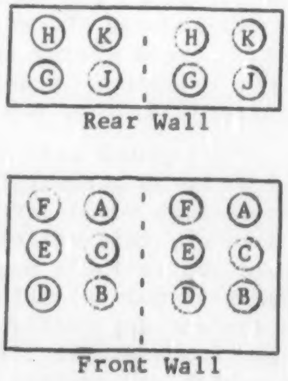
TABLE 6-9

EXPERIMENTAL DESIGN WITH RUN NO., % O2 AND PPM NO_x

(Leland Olds, Boiler No. 1)

	L_1 - 218 MW Gross Load		L_2 - 180 - 192 MW Gross Load	
	A_1 - Normal Excess Air	A_2 - Low Excess Air	A_1 - Normal Excess Air	A_2 - Low Excess Air
S_1 All Burners Firing	(1) 3.9%-569 (1A) 3.6%-564	(2) 2.1%-447		
S_2 F Mill On Air Only	(3) 4.2%-560	(4) 2.8%-375		
S_3 F & K Mills Air Only				(5) 3.5%-342
S_4 A & F Mills Air Only			(6) 4.9%-428	(7) 2.2%-260
S_5 A & H Mills Air Only				(9) 2.6%-329
S_6 A & K Mills Air Only				(11) 3.5%-356
S_7 A Mill Air Only		(4A) 2.6%-418 (4B) 2.7%-401 (4C) 3.1%-475		

* Runs 4A, 4B and 4C conducted at 205 MW.

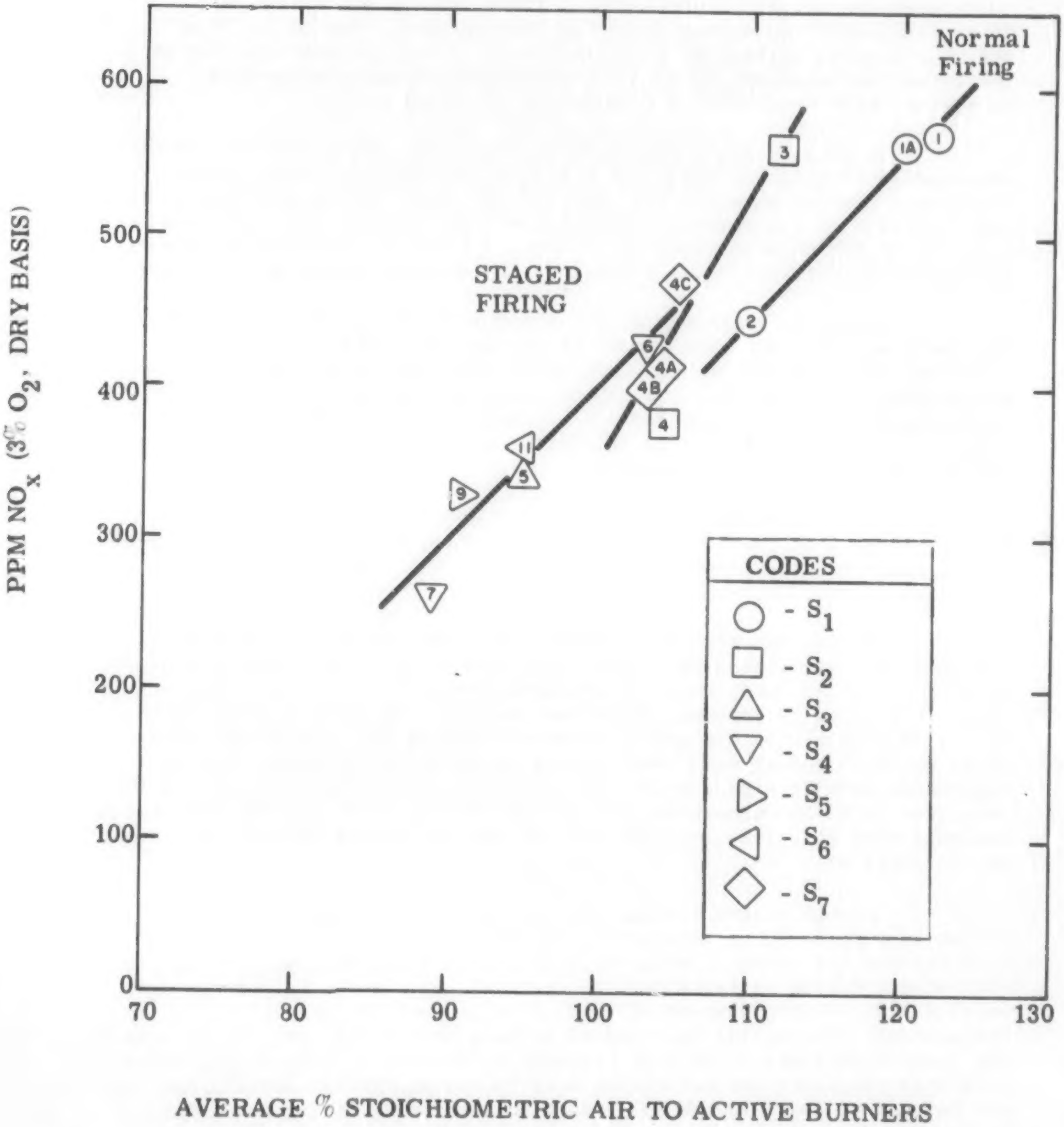


Mill-Burner Configuration

FIGURE 6-12

PPM NO_x (3% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(LELAND OLDS, BOILER NO. 1)



6.1.1.2.3 Four Corners, Boiler No. 4

Arizona Public Service's No. 4 Boiler at their Four Corners Station was also tested according to our planned test program design, except that continuous electricity demand on the station prevented testing at low loads, and the currently inoperative flue gas recirculation system could not be utilized due to erosion problems. This unit, with a maximum rated capacity of 800 MW gross load, is a single furnace (with division wall), pulverized coal fired Babcock and Wilcox boiler. It is fired with low sulfur, high ash Western coal. Boiler No. 5 at the Four Corners Station is a "sister"-unit of similar size and design. The latter was used for determining accelerated furnace water-tube corrosion rates under baseline operating conditions.

In each of these two boilers, nine pulverizers feed 54 burners, arranged in 18 cells of three burners each, as shown in Figure 6-13. The front wall has ten burner cells, while eight burner cells are located in the rear wall of the furnace. Each boiler can maintain the full load capacity of 800 MW with eight or nine pulverizers in operation when good quality coal is fired, and all equipment is in good operating condition.

Operating variables during the short-term optimization phase of the tests were boiler load, burner firing pattern, excess air level, secondary air register setting, and water injection (used for improving precipitator efficiency). Our gaseous sampling system was modified to allow sampling from 18, instead of the usual 12 duct positions, with two three-probe assemblies each in the north, middle, and south ducts between the economizer and the air heaters.

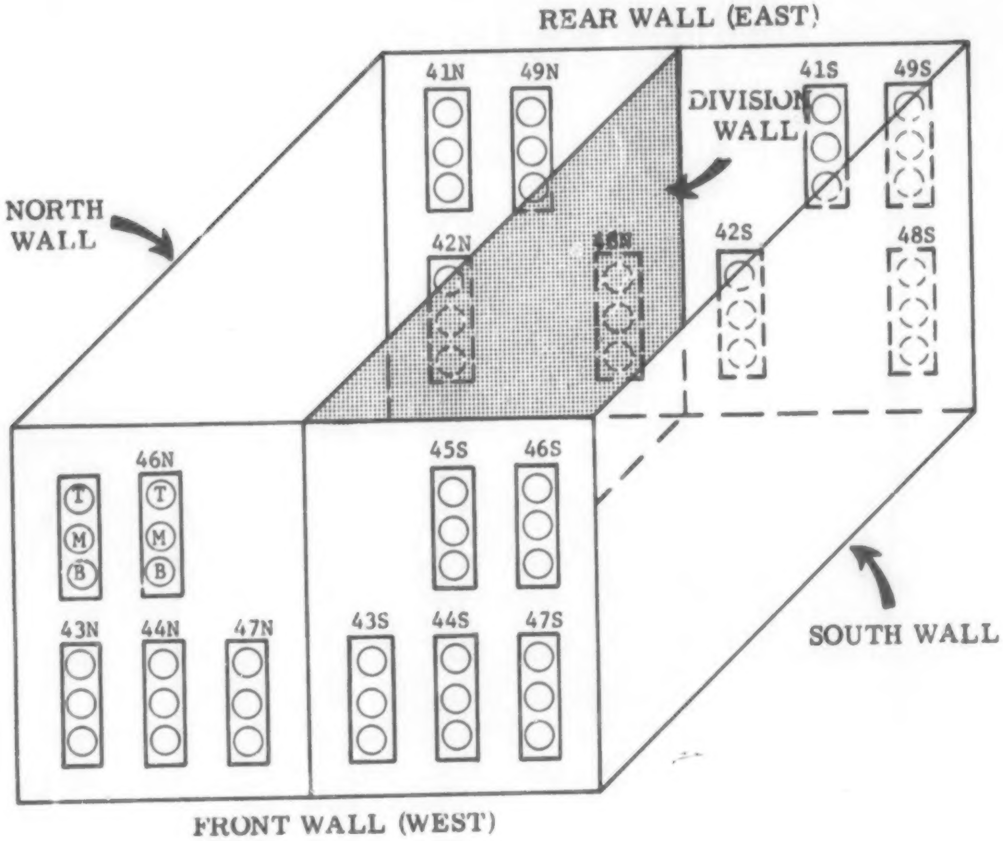
Table 7, Appendix A contains a summary of the operating and emission data from the 26 test runs completed on this boiler. Table 6-10 below, indicates the experimental design with run number, % oxygen and ppm NO_x.

The NO_x emission data measured are summarized in Figure 6-14. Baseline NO_x emissions under normal operating conditions averaged a high level of about 935 ppm, which is consistent with that expected from a large, horizontally opposed, coal-fired boiler. Reducing the per cent stoichiometric air to the active burners consistently reduced NO_x emissions for both normal and staged firing as shown by the least squares regression line of Figure 6-14. The expected reductions in NO_x for a 10% reduction in % stoichiometric air calculated from least squares regression analysis were 147, 184, 147, 159 and 166 ppm for firing patterns S_1 through S_5, respectively.

Through staged firing, the average % stoichiometric air to the active burners could be reduced considerably below the minimum level of 110% reached for normal firing, thus producing lower NO_x emission levels. Four staged firing patterns were tested: (1) S_2 - top 8 burners on air only, (2) S_3 - 2 top burners of 4 cells on air only to produce a "tangential" effect, (3) S_4 - top 12 burners on air only and (4) S_5 - cells fed from pulverizers 5 and 9 on air only to produce a "tangential" effect. Full load operation was maintained with S_3 and S_4 firing, while gross load was reduced to about 730 MW (9% reduction) during S_2 firing and reduced to 600 MW during S_4 type operation. NO_x emissions under full load, low

FIGURE 6-13

FOUR CORNERS STATION, BOILER NO. 4
PULVERIZER-BURNER CONFIGURATION


REAR WALL (EAST)
41N
49N
41S
49S
DIVISION WALL
NORTH WALL
42N
48N
42S
48S
46N
T
M
B
T
M
B
45S
46S
43N
44N
47N
43S
44S
47S
SOUTH WALL
FRONT WALL (WEST)

9 PULVERIZERS NUMBERED 41 THROUGH 49.
18 BURNER CELLS NUMBERED WITH PULV. NO. "N" OR "S" FOR NORTH OR SOUTH OF DIVISION WALL.
54 BURNERS DESIGNATED "T", "M" OR "B" FOR TOP, MIDDLE OR BOTTOM OF OF EACH CELL.

E.G., 45NT IS TOP LEFT BURNER IN FRONT WALL OF NO. 4 BOILER
→ TOP BURNER OF CELL
→ NORTH SIDE OF DIVISION WALL
→ NO. 5 PULVERIZER
→ NO. 4 BOILER

TABLE 6-10

EXPERIMENTAL DESIGN - % OXYGEN AND PPM NO_x (3% O_2, DRY BASIS)

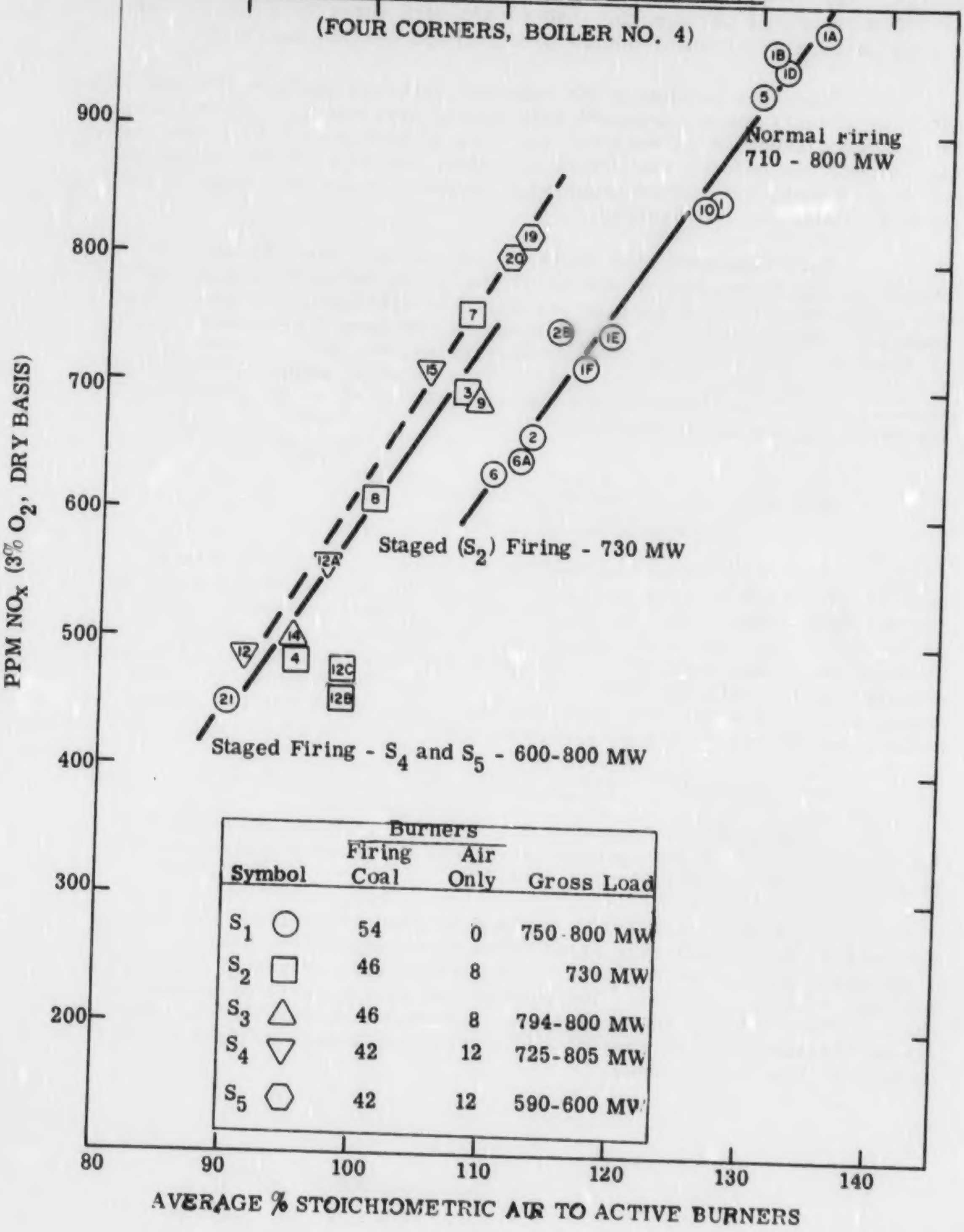
(Four Corners, Boiler No. 4)

	L_1 - 710 - 810 MW Gross Load				L_2 - 590 - 600 MW Gross Load			
	A_1 - Normal Excess Air		A_2 - Low Excess Air		A_1 - Normal Excess Air		A_2 - Low Excess Air	
	D_1 - Open Sec. Air	D_2 - 1/2 Open Sec. Air	D_1 - Open Sec. Air	D_2 - 1/2 Open Sec. Air	A_1 - Open Sec. Air	D_2 - 1/2 Open Sec. Air	D_1 - Open Sec. Air	D_2 - 1/2 Open Sec. Air
S_1 - Normal Firing 54 Burners Firing Coal	(1A) 5.6-982 (1) 4.6-848 (1B) 5.1-965 (1C) 4.5-843 (1D) 5.2-949 (1E) 3.4-741* (1F) 3.1-715*	(5) 5.0-932	(6A) 2.3-641 (6) 2.0-630	(2) 2.5-659 (2B) 2.8-748				
S_2 - 8 Top Burners On Air Only	(7) 4.7-754	(3) 4.6-695	(4) 2.2-482 (12B) 3.7-458* (12C) 2.8-473*	(8) 3.3-609				
S_3 - Simulated Tangential 8 Burn on Air	(9) 4.6-685		(14) 2.3-494					
S_4 - 12 Top Burners On Air Only	(15) 5.5-709		(12) 3.2-488					
S_5 - No. 5 & 9 Mill Burners On Air Only					(19) 6.5-816 (20) 6.4-801		(21) 3.0-452	

* 100-200 gal. water/hour injected into furnace.

FIGURE 6-14

PPM NO_x (3% O_2, DRY) VS %
STOICHIOMETRIC AIR TO ACTIVE BURNERS



excess air, staged operation (S_3 and S_4) were reduced to about 490 ppm or by about 48% from baseline operation. Operation with firing pattern S_2 at 730 MW produced 482 ppm NO_x (458 to 473 with water injection), while firing pattern S_5 at about 600 MW produced 452 ppm NO_x emissions.

Wide open secondary air register settings could reduce NO_x emissions by a small amount compared with closed settings (presumably because of reduced combustion intensity), but only in combination with low excess air firing. As before, the effect of damper settings on NO_x emissions was significant, but second-order with respect to the main effects of reduced excess air and staging.

Data from test runs numbered 12C and 12B were obtained with staged firing (8 burners on air only) while the boiler operator used water injection to help improve precipitator efficiency for particulate removal. The reduction in NO_x of about 80 ppm from the expected level of about 543 ppm is not altogether surprising, based on our estimate of 0.2 lb. H_2O injected/lb. coal fired. This quantity of water injection should reduce flame temperatures sufficiently to allow for the above degree in NO_x emission reduction.

6.1.1.3 Gaseous Emissions from Tangentially Fired Boilers

Four Combustion Engineering designed, tangentially fired, pulverized coal boilers were tested: Barry No. 3, 250 MW; Naughton No. 3, 325 MW; Dave Johnston No. 4, 348 MW; and Barry No. 4 rated at 350 MW gross load. The number of burners and burner levels were 20 and 5 for Naughton No. 3 and Barry No. 4, 48 and 6 for Barry No. 3, and 28 burners arranged in 7 levels for Dave Johnston No. 4. The Naughton and Dave Johnston boilers were fired with Western coals, while the two Barry boilers tested were fired with Alabama coal.

6.1.1.3.1 Barry, Boiler No. 3

Alabama Power Company's Boiler No. 3 at their Barry Station was tested at the boiler operator's request for gaseous emissions only in a short-term optimization program.

This unit is a 250 MW maximum continuous rating, twin furnace, tangential, pulverized coal fired Combustion Engineering boiler. It has a separated furnace arrangement, with radiant and horizontal superheater surfaces in both furnaces. The pendant and platen sections constitute the superheat surface in one furance, and reheat surface in the other one. Six pulverizers feed 24 tangential burners (six levels of four burners) in each of the two furnaces.

This boiler was of special interest, because of the small value of 31.25 MW per "equivalent furnace firing wall". Our correlation based on previously obtained data for coal fired boilers (4) would predict a baseline (20% excess air) NO_x emission level of 412 ppm for this parameter. Actual measurements for run 1 baseline operation resulted in a NO_x value of 410 ppm, in good agreement with the correlation.

Table number 8 of Appendix A contains a summary of operating and emission data for the 8 test runs completed on this boiler. Table 6-11 shows the experimental design with average % oxygen and ppm NO_x for each run.

Operating variables included in the test program were excess air level, air damper settings, and pulverizer mill fineness setting. Planned reduced load and staged firing tests could not be implemented, because mechanical problems with a condenser water valve prevented such operation, despite all the efforts of the plant personnel to correct this problem.

As expected, excess air level exerted a major effect on NO_x emissions. These results are shown in the least squares regression line of Figure 6-15. From a baseline level of about 412 ppm at 117% stoichiometric air to the burners, NO_x emissions were reduced by about 24% to 310 ppm at 106% stoichiometric air. The effect of damper settings was very small, 7%, and that of mill fineness was negligible. The normal practice of 100% open auxiliary dampers and 40% open coal dampers produced lower NO_x emissions than the reverse damper settings.

6.1.1.3.2 Naughton, Boiler No. 3

Utah Power and Light's No. 3 boiler at their Naughton Station was one of two modern, 320 to 350 MW maximum rated single furnace, pulverized coal fired, Combustion Engineering boilers tested. The other one was Alabama Power's No. 4 Boiler at their Barry Station. Both boilers have five levels of four corner burners each. Gaseous emission results obtained in testing the latter unit will be presented in a subsequent section of this report.

Naughton unit No. 3 was designed to fire a sub-bituminous, low heat content (9,500 Btu/lb. HHV), low sulfur, high moisture content, Western coal. The boiler was designed for a larger turbine-generator than the one actually installed. This factor, in combination with the lack of "seasoning" of the superheat and reheat surfaces, and the type of coal fired in this new unit has resulted in a steam temperature control problem. The use of tilting burners and attemperation water are the means available for controlling steam temperatures. To the date of our tests it had been necessary at load levels exceeding 280 MW to tilt the burners

TABLE 6-11

TEST PROGRAM EXPERIMENTAL DESIGN - BARRY, BOILER NO. 3

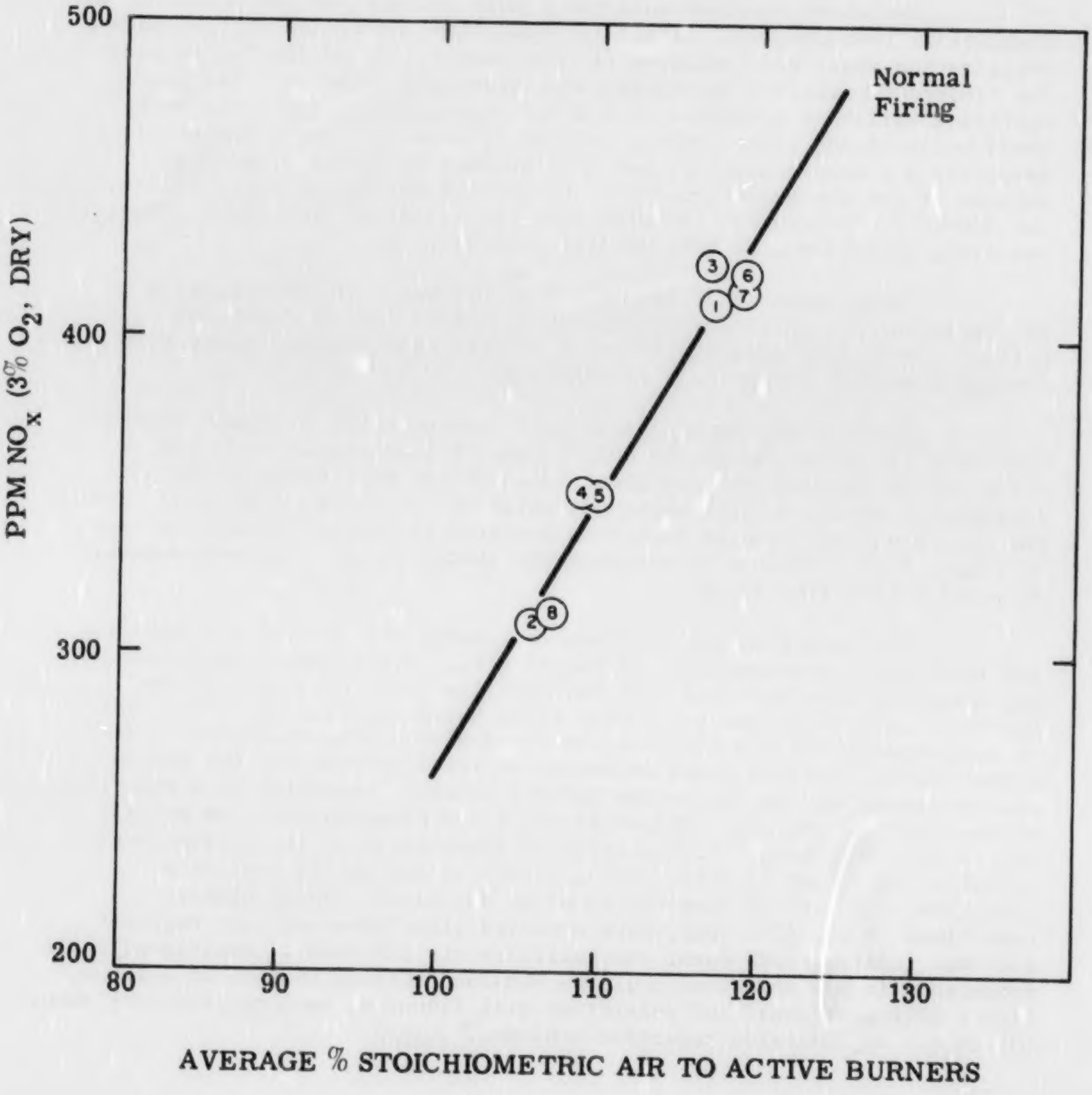
(Run No., Average % Oxygen, and ppm NO_x (3% O_2 Dry Basis) Measured in Flue Gas)

		L_1 250 MW	
		S_1 All Mills Firing Coal	
		A_1 Normal Excess Air	A_2 Low Excess Air
D_1 Secondary Air Dampers 100% Aux. 30% Coal	F_1 Normal Mill Fineness	(1) 3.1 - 410	(2) 1.3-310
	F_2 Coarse Mill Fineness	(7) 3.5 - 402	(8) 1.4-312
D_2 Secondary Air Dampers 40% Aux. 100% Coal	F_1 Normal Mill Fineness	(3) 3.2 - 425	(4) 1.9-350
	F_2 Coarse Mill Fineness	(6) 3.5 - 420	(5) 2.0-350

FIGURE 6-15

PPM NO_x (3% O2 DRY BASIS) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(BARRY, BOILER NO. 3)



down, add attemperation water, lower excess air, and use furnace soot blowers almost continuously. It may be necessary, according to Combustion Engineering representatives, to reduce the reheat surface area to overcome this control problem.

Other operating problems encountered in this test program were furnace slagging (particularly at high loads, with low excess air and tilting burners down) even under normal operating conditions, and the high silica content of the boiler feed-water, caused by pin-hole leaks in the condenser tubing.

The above problems were taken into account for the design of the statistical test program. Except for base line tests, our short-term NO_x optimization phase was conducted at less than full load levels, to avoid the limited flexibility associated with operating problems. The six operating variables studied in the short term optimization tests were gross boiler load, burner firing pattern, excess air level, burner tilt, secondary air damper setting, and coal pulverizer fineness setting. Because of the above-mentioned operating problems with this new boiler, the 300-hour accelerated corrosion test was performed only under normal operating conditions, as will be discussed later.

Table number 9 of Appendix A is a summary of the operating and emission data obtained from the 26 test runs completed on this boiler. Table 6-12 presents the test program experimental design with average % oxygen and ppm NO_x for each test run.

Baseline NO_x emissions at full load measured 531 ppm. Reducing load from 334 MW to 200 MW (by 40%) reduced NO_x emissions by 73 ppm (from 531 to 458 ppm) or only about 14%. Coarse mill fineness had a detrimental effect of increasing NO_x emissions by about 40 ppm (17%) during the low excess air, staged operation compared to normal fineness as shown in Figure 6-16. Table 6-13 presents the change in coal fineness measured on samples from four mills.

The emission data obtained in testing this boiler are shown by the least squares regressions of Figure 6-17. Significant reductions in NO_x emissions were achieved from the baseline level of about 530 ppm (which is relatively low for a coal fired boiler of this size, but typical of tangentially fired units from the standpoint of NO_x emissions). With normal firing, quite a steep decrease was found by reducing the percent stoichiometric air to the active burners to 110%, resulting in a reduction of about 30% to 380 ppm. Staged firing in combination with low overall excess air (less than stoichiometric air/fuel ratio in the active burners) at 90% of full load resulted in NO_x levels as low as 219 ppm, or a reduction of about 60% from the baseline NO_x level. These highest reductions in NO_x (311 ppm), were achieved with "abnormal" air register settings (coal-air 30% open, and auxiliary air 20% open). Additional small reductions in NO_x emissions could be obtained through the use of optimum burner tilt positions, and pulverizer mill fineness, each contributing about 10% to the NO_x emission reduction achieved.

TABLE 6-12

TEST PROGRAM EXPERIMENTAL DESIGN - NAUGHTON, BOILER NO. 3

(Run No., Average % Oxygen and ppm NO_x (3% O_2, Dry Basis) Measured In Flue Gas)

		L_1 - 328 - 340 MW		L_2 - 300 - 315 MW			L_3 - 250 - 275 MW				L_4 - 200 MW			
		A_1 - All Pulv. Firing		S_1-	S_2 - Top Pulv. Air Only		S_1-	S_2 - Top Pulv. Air Only			S_1-	S_3 - 2 Pulv. Off, Top Pulv. Air Only		
		A_1-Nor. Exc. Air	A_2 - Lea	A_1 - Nea	A_2 - Low Excess Air		A_1 - Nea	A_1 - Nea	A_2 - Low Excess Air		A_1 - Nea	A_1 - Nea	A_2 - Low Excess Air	
[1] Secondary Air		D_1-	D_1-	D_1-	D_1-	D_2-	D_1-	D_1-	D_1-	D_2-	D_1-	D_1-	D_1-	D_2-
C_1 Normal Mill Fineness	T_1 - Horiz. Burner Tilt	(18) 3.9 494 (26) 4.4 568	(19) 2.0 379		(20) 2.7 236	(21) 2.3 219	(1) 4.9 537	(2) 4.9 304 (22)*3.1 331	(3) 3.6 265	(10) 3.0 197	(14) 4.2 458	(15) 4.5 169	(16) 3.2 182	(17) 4.2 176
	T_2 - Down Burner Tilt			(24) 3.6 569 (25) 4.2 549			(23) 3.6 510		(4) 3.7 266 (6) 3.1 216	(7) 3.0 213				
	T_3 - Up Tilt								(5) 3.6 284	(11) 3.5 216				
C_2 Coarse Mill Fineness	T_1-Hor. Tilt									(13) 3.7 235				
	T_2 - Down								(9) 3.1 245	(8) 3.2 251				
	T_3-Up Tilt									(12) 3.7 273				

* Top pulverizer off with 2nd air registers partly open.

[1] Secondary air registers: D1 - 20% auxiliary air, 80% coal air; D2 - 60% auxiliary air, 20% coal air.

FIGURE 6-16

EFFECT OF MILL FINENESS AND BURNER TILT ON NO_x EMISSIONS FOR LOW EXCESS AIR STAGED FIRING

(NAUGHTON, BOILER NO. 3)

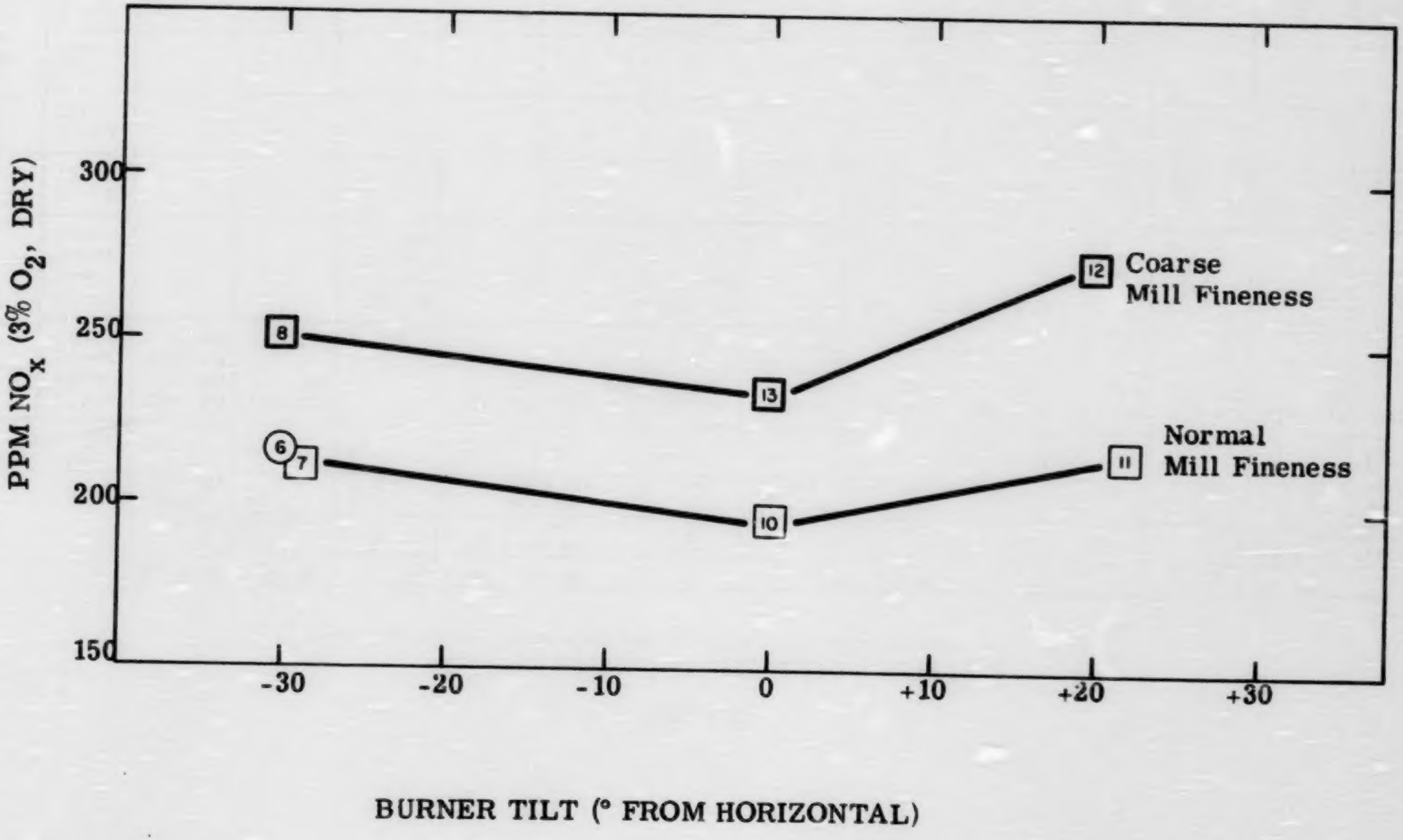


TABLE 6-13

PULVERIZER SCREEN ANALYSES
NAUGHTON, BOILER NO. 3
(Normal vs. Coarse Classifier Setting*)

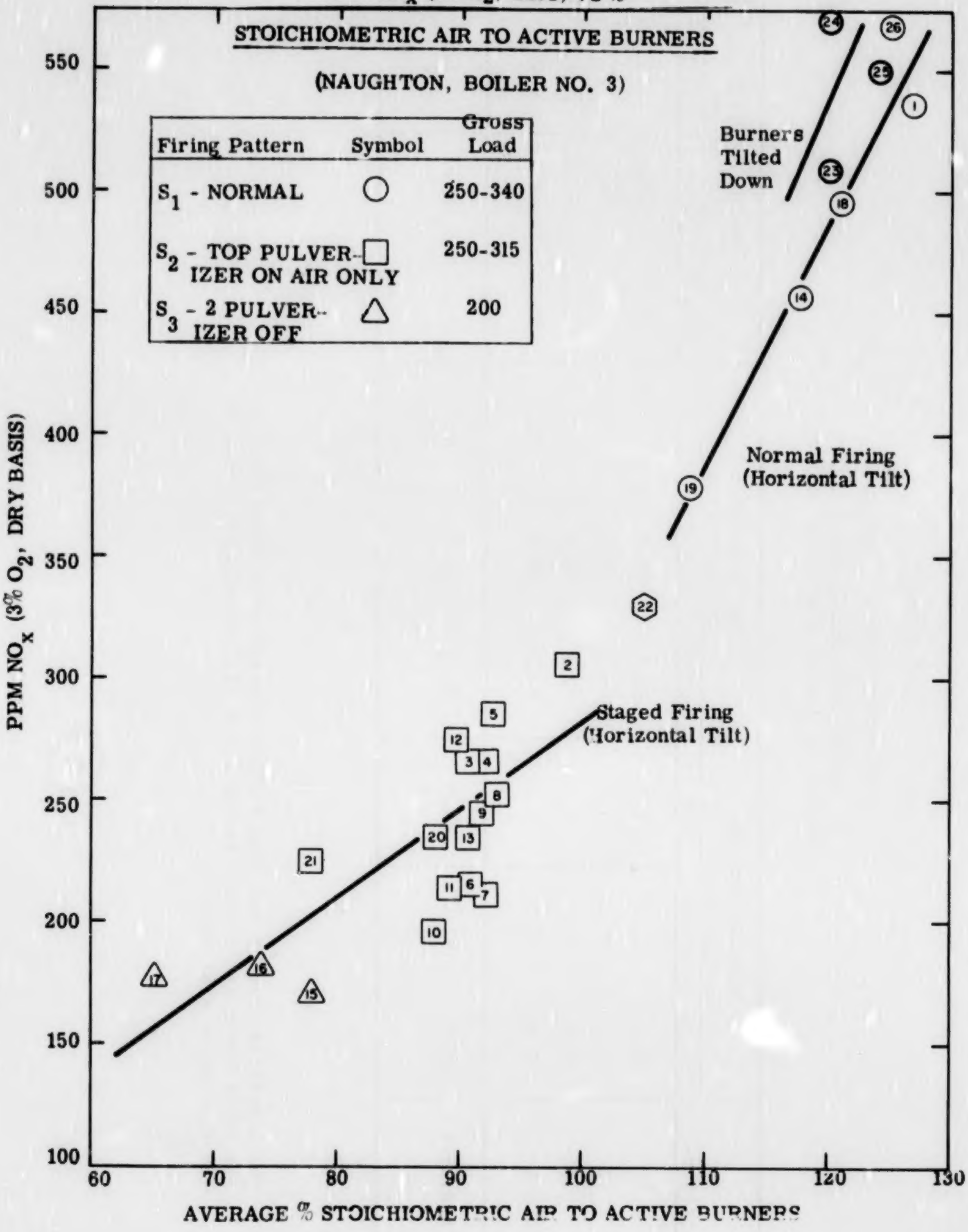
Mill No.	% Passing Through 48 Mesh Screen			% Passing Through 100 Mesh Screen			% Passing Through 200 Mesh Screen		
	Normal	Coarse	Diff. %	Normal	Coarse	Diff. %	Normal	Coarse	Diff. %
1	99.2	97.2	2.0	88.4	82.0	6.4	76.7	60.9	15.8
2	99.6	98.2	1.4	95.2	87.6	7.6	75.4	64.6	10.8
3	99.0	96.6	2.4	89.6	84.1	5.5	65.1	61.6	3.5
4	99.4	97.3	1.8	90.8	83.6	7.2	69.3	64.8	4.5
Averages	99.3	97.4	1.9 t = 9.1	91.0	84.3	6.7 t = 14.4	71.6	63.0	8.6 t = 3.0

* The classifier can be set from 0 (very coarse) to 4 (very fine). For these tests the classifier was set at 2.1 normally and at 1.0 for the coarse test runs.

FIGURE 6-17

PPM NO_x (3% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(NAUGHTON, BOILER NO. 3)



6.1.1.3.3 Barry, Boiler No. 4

Alabama Power's Boiler No. 4 at their Barry Station was tested successfully through all three phases of our test program design. Representatives of Combustion Engineering actively participated in this series of tests. As mentioned before, this new 350 MW maximum rated capacity, single furnace, pulverized coal fired Combustion Engineering boiler is similar to Naughton unit No. 3. Both are representative of that manufacturer's current design practices. In Barry No. 4, five pulverizers feed 20 burners that are corner-mounted at five levels of the furnace. This boiler is designed for firing Eastern bituminous coal having a HHV of 12,000 Btu/lb.

Table Number 11, Appendix A contains a summary of the operating and emission data obtained from the 46 test runs completed on this boiler. Table 6-14 shows the test program experimental design with % oxygen and ppm NO_x listed for each test run. For this boiler, flue gas samples were taken from ducts after the air preheater. Regression analysis of simultaneous measurements of the O_2 concentration upstream and downstream of the air preheater in several test runs provided a basis (see Figure 6-18) for estimating the excess air supplied to the furnace.

Seven operating variables were varied independently in the short period NO_x optimization phase of the test program. Gaseous emission data obtained from this phase are presented in the least squares correlations of Figure 6-19. As discussed below, the most important variables from the standpoint of NO_x emission control were excess air level, staged firing, and burner tilt. Boiler load, secondary air register settings, type of coal and coal fineness were less important.

Baseline NO_x emissions at full load were only 423 ppm due in part to the relatively low level of excess air (15%), and to the tangential mode of firing. Excess air level was the most important variables as shown by the regression lines of Figure 6-19. Under normal firing operation with horizontal burner tilt an eight % reduction of excess air (from 15% to 7%) reduced NO_x to 350 ppm, or by 17%.

Burner tilt also had an important effect on NO_x emission rates. Down tilt operation increased NO_x emission by an average of 53 ppm (14%) under normal firing, and by 5% under staged firing compared to horizontal burner tilt. Up tilt gave a small further improvement but caused steam temperature control problems and increased oxygen stratification between flue gas ducts.

Staged firing (top pulverizer off) at 280 to 325 MW resulted in lowering NO_x emissions by about 34% (to about 280 ppm) when operating with 90% stoichiometric air to active burners. Staged firing with the top two pulverizers off at 185 MW produced less than 200 ppm NO_x under low excess air firing.

TABLE 6-14

TEST PROGRAM EXPERIMENTAL DESIGN - BARRY, BOILER NO. 4

(Run No. Average % Oxygen and PPM NO_x (3% O_2, Dry Basis) Measured in Flue Gas)

			L_1 - 325 - 360 MW (Gross Load)			L_2 - 280 - 325 MW (Gross Load)				L_3 - 180 - 210 MW (Gross Load)					
			S_1 - All 5 Pulv. Firing Coal			S_1 - 4 Pulv. Firing	S_2 - Top Pulverizer on Air Only			S_1 -	S_3 - Top 2 Pulv. Off; Top Pulv. Air Only			S_4 - Top Pulv. Air Only; C Mill Off	
			A_1-Nor. Exc. Air	A_2-Low Excess Air		A_1-Nor. Exc. Air	A -Nor. Exc. Air	A_2-Low Excess Air		A_1-Nor. Exc. Air	A_1-Nor. Exc. Air	A_2-Low Excess Air		A_1-Nor. Exc. Air	A_1-Nor. Exc. Air
		(1)	D_1-Nor. Setting	D_1-Nor. Setting	D_2-Rev. Setting	D_1-Nor. Setting	D -Nor. Setting	D_1-Nor. Setting	D_2-Rev. Setting	D_1-Nor. Setting	D_1-Nor. Setting	D_1-Nor. Setting	D2-Rev. Setting	D_1-Nor. Setting	D_1-Nor. Setting
C_1 Alabama Coal With C Pulv. Firing Petr. Coke	F_1 - Normal Mill Fineness	T_1-Horiz. Tilt	(1) 4.4-415	(2) 3.9-398 (42)* 3.9-396 (43)* 2.7-349	(35) 3.8-409 (37) 3.9-441	(50)* 4.4% 436	(5) 5.4% 313	(6) 4.8% 286	(9) 4.4% 295						
		T_2-Down Tilt	(33) 4.3% 497	(34) 3.1% 445	(4) 2.5% 364			(10) 3.0% 289	(8) 2.4% 257						
		T_3-Up Tilt		(3) 3.6% 349				(7) 4.4% 294							
	F_2 - Coarse Mill Fineness	T_1-Horiz. Tilt							(12) 4.3% 297						
		T_2-Down Tilt						(11) 2.9% 299							
C_2 Alabama Coal On All Pulv.	F_1 - Normal Mill Fineness	T_1-Horiz. Tilt	(13) 4.7-420 (13A) 3.8-415	(29) 2.8% 336			(14) 5.1% 309	(15) 3.6% 245							
		T_2-Down Tilt			(31) 2.8% 398				(16) 3.3% 264						
		T_3-Up Tilt		(30) 3.6% 336											
C_3 Midwest Coal + C. Pulv. Firing Coke	F_1 - Normal Mill Fineness	T_1-Horiz. Tilt	(17) 5.1% 441			(42A) 5.0-396 (42B) 4.5-370	(18) 6.3% 334	(19) 4.9-283 (19A) 4.4-308 (19E) 4.0-275	(32) 5.7% 282	(25) 6.0% 440	(27) 7.1% 260	(26) 3.7% 189		(40) 7.7% 338	(41) 3.9% 200
		T_2-Down Tilt							(20) 3.1% 273				(28) 4.3% 232		

(1) Secondary air register settings: normal, auxiliary 100% open and coal 50% open; reversed, auxiliary 50% open, coal 100% open.
* Secondary air registers: Auxil. - 40% open, Coal - 50% open.

FIGURE 6-18

% OXYGEN MEASURED IN FLUE GAS BEFORE AND AFTER AIR PREHEATER

(BARRY, BOILER NO. 4)

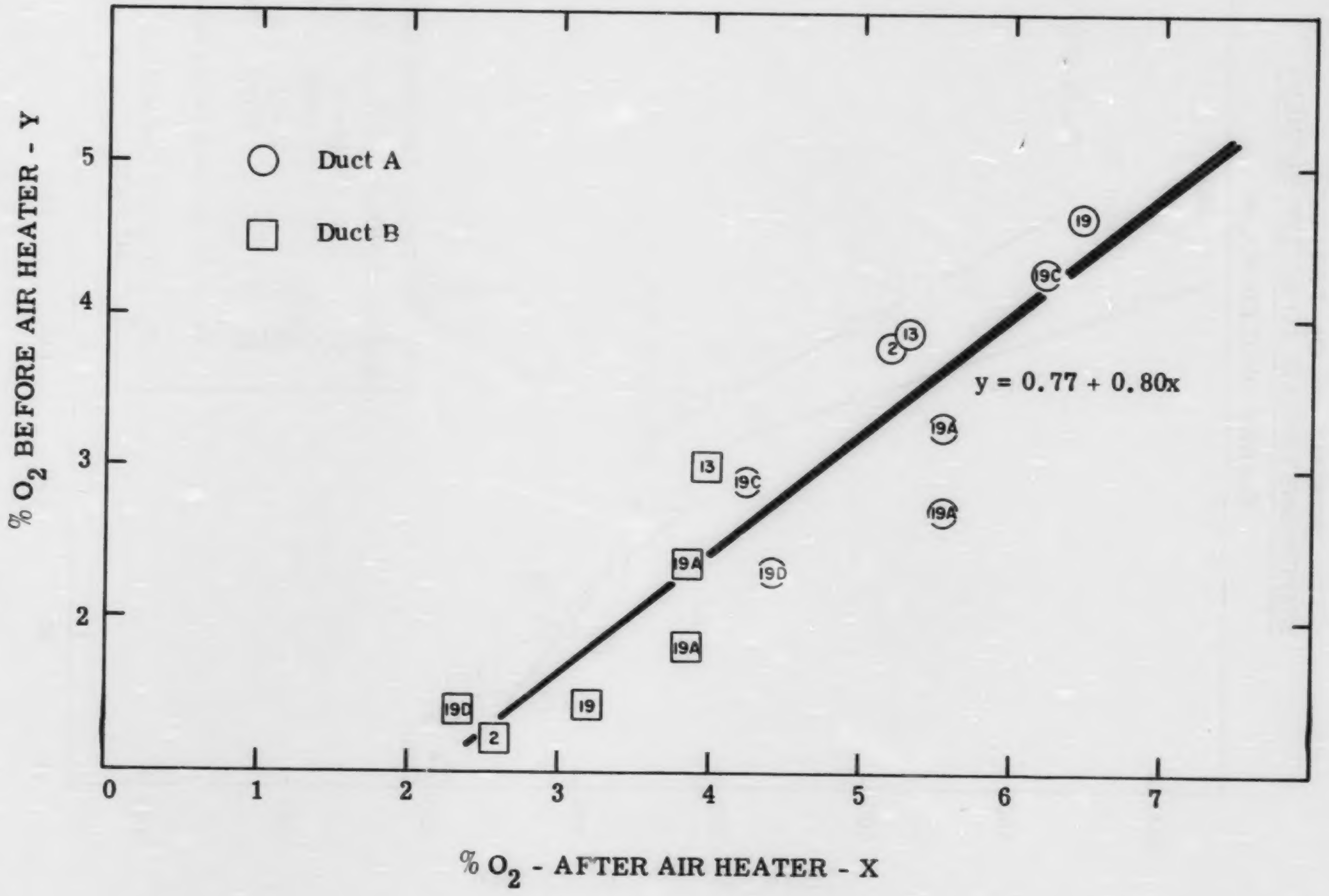
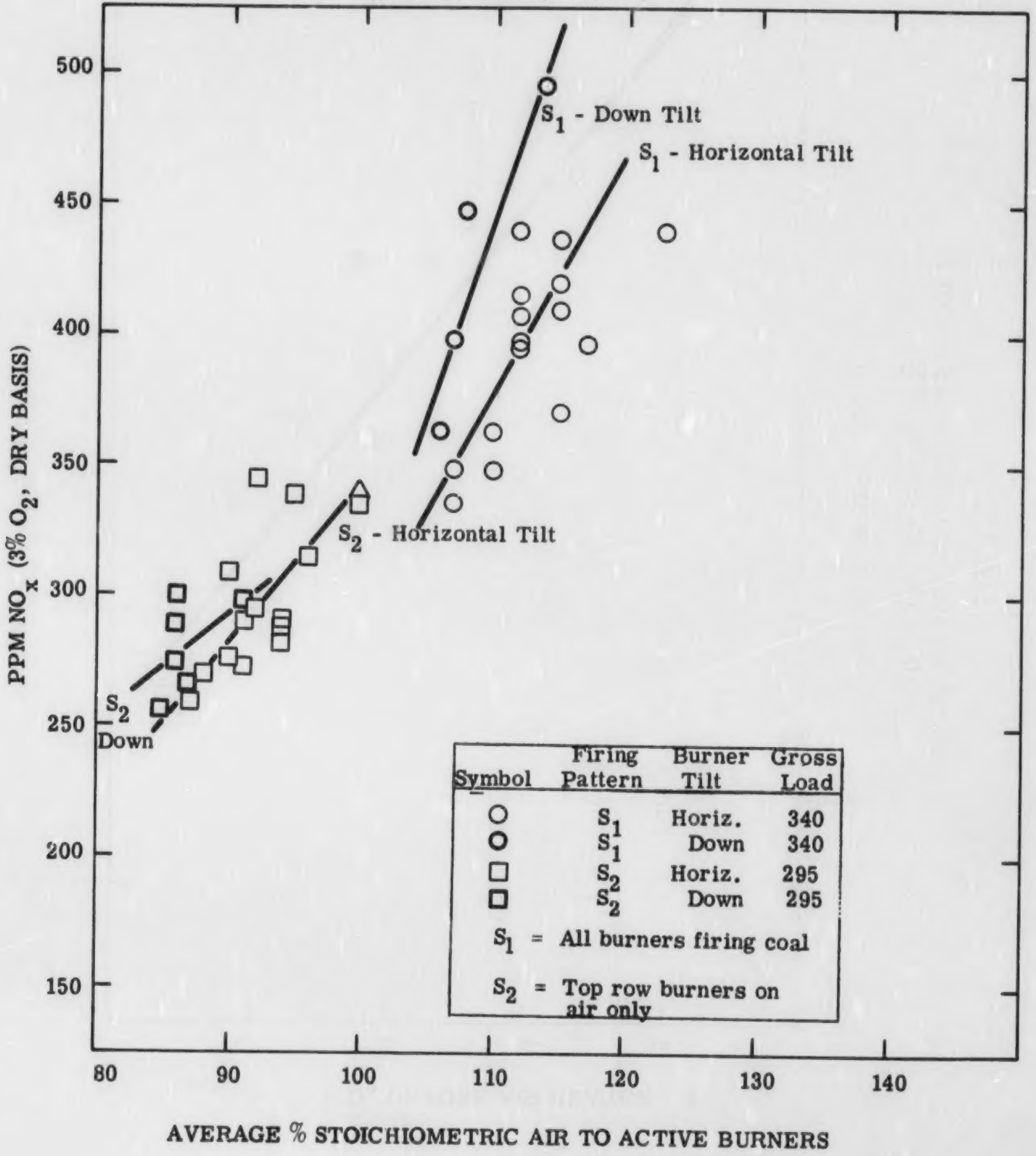


FIGURE 6-19

PPM NO_X (3% O_2, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

(BARRY, BOILER NO. 4)



The effect of secondary air registers settings on NO_x emissions depended upon the burner tilt position. With horizontal burner tilt, normal damper settings (auxiliary 100% open and coal 50% open) produced about 7% less NO_x than reversed settings. However, with burners tilted down, reversed damper settings generally produced lower NO_x emissions than did normal settings.

Boiler load, coal type and coal fineness were minor operating variables from the standpoint of NO_x emission control. Reducing load by 12% reduced NO_x levels by about 9% which is in line with our results obtained on other coal fired boilers. Coal source had a small, but satistically significant effect on NO_x emission levels. Alabama coal test runs produced about 23 ppm higher NO_x emissions than did Midwest coal after allowing for differences in excess air levels. This difference is possibly explained by the slightly higher nitrogen content of the Alabama coal. Pulverizer coal fineness was changed to coarse in only two test runs, and NO_x results obtained did not show statistically significant differences.

Petroleum coke was fired through the middle level burners (Pulverizer "C") on most test runs. Comparison of the eight test runs conducted with Alabama coal fed to all pulverizers with similar runs firing petroleum coke or petroleum coke/coal mixtures indicated no statistically significant differences in NO_x emission levels.

6.1.1.3.4 Dave Johnston, Boiler No. 4

Boiler No. 4 at the Dave Johnston Station of Pacific Power and Light is a Combustion Engineering Company designed, tangentially fired, single furnace boiler with a maximum continuous rating of 2,450,000 pounds of primary steam generated per hour or about 348 MW gross load. Seven pulverizers feed coal to 28 tilting tangential burners located at the corners of 7 elevations. The furnace is 50 feet wide and 42 feet deep with a volume of 280,000 cubic feet. Design operating conditions at maximum continuous rating include steam temperatures of 1005°F leaving the superheater and the reheater turbine throttle pressure of 1890 psig, and reheat to the boiler of 475 psig and 670°F.

Table 10 of Appendix A contains a summary of operating and emission data for the six test runs completed on this boiler. Maximum load was limited by ID fan capacity due to plugging of the air preheaters. Therefore, our test runs were made at a reduced load of 303-312 MW instead of 345-350 MW full load. Normally, this boiler can operate at full load with one or two pulverizers off. During our test period it was not possible to remove the top mill without reducing load since there were always two other mills off, due either to mechanical problems or to necessary, scheduled maintenance. Thus, no staged firing tests were possible. Operating variables included in the experimental program were mills off, excess air level, burner tilt and primary air flow rate. The variation in primary air (coal transport air) flow rate was made in order to achieve higher loads without increasing ID fan output.

Table 6-15 indicates the experimental design of operating variables with average flue gas measurements of % O_2 and ppm NO_x (3% O_2, dry basis) shown for each test run. Figure 6-20 is a plot of ppm NO_x vs % stoichiometric for the data collected during our test runs.

Analysis of the flue gas emission data indicated a consistent difference in flue gas measurements from duct "A" (probes 1 and 2) and duct "B" (probes 3 and 4) generally characteristic of tangentially fired boilers. Duct "A" averaged about 2.3% oxygen and 20 ppm NO_x, respectively, less than the corresponding measurements from "B" duct. This difference in oxygen levels may be attributed to different burning rates prevailing due to he centrifugal separation of larger coal particles arriving to the furnace arch, before the flue gas stream is split into two ducts.

Baseline NO_x emission rates at partly reduced load (12% from full load) were 434 ppm (3% O_2, dry basis). Reducing excess air from 124 to 113% of stoichiometric reduced NO_x emissions to 384 ppm, or by 12%. Operating with burners tilted down resulted in raising NO_x emissions by 40 ppm, or about 10%. Test runs No. 10 and 17 were conducted with increased primary air damper openings so that more coal would be transported with the same fan settings as used in previous test runs, and consequently the load would be at increased levels. NO_x emissions rates were about 13% lower in these test runs than corresponding earlier test runs. Horizontal burner tilt operation produced less NO_x emissions than down tilt burner operation. Additional experiments are needed to verify these results.

6.1.1.4 Gaseous Emissions from Turbo-Furnace Boilers

6.1.1.4.1 Big Bend, Boiler No. 2

Tampa Electric Company's Boiler No. 2 at their Big Bend Station has been the only Riley-Stoker turbo-furnace unit tested by Esso under EPA sponsorship. This pulverized coal fired, 450 MW maximum continuous rating, single furnace boiler is fed by three pulverizer mills. Altogether, 24 Riley directional flame burners are fired normally, with one row of 12 burners in the front wall, and another row of 12 burners in the rear wall.

Maximum load was limited to 375 MW, due to steam temperature, potential slagging, and other operating problems not related to our test program. (It is our understanding that until the time of our test, gross load on this unit had never exceeded 400 MW.) Excess air was set at normal operating levels, or at the minimum level dictated by maximum acceptable CO levels measured in the flue gas, and in the slag catcher at the bottom of the furnace. Other operating variables included in the statistically designed short-term phase (this was the only phase of our overall program design performed at Big Bend) were operating with fly-ash reinjection (practiced to improve carbon burn-out efficiency and slagging characteristics) or without it, and positioning of the

TABLE 6-15

EXPERIMENTAL DESIGN WITH % O_2 AND PPM NO_x (3% O_2 BASIS)

(Dave Johnston Station, Boiler No. 4)

	S_1 Normal Firing Pattern (Mills 17 & 20 Off)				S_2 Staged Firing Top Mill - Air Only**			
	A_1 Normal Excess Air		A_2 Low Excess Air		A_1 Normal Excess Air		A_2 Low Excess Air	
Burner Tilt \ *Primary Air	P_1	P_2	P_1	P_2	P_1	P_2	P_1	P_2
T_1 Horizontal	(1) 4.2-434	(10) 3.9-362	(2) 3.2-386	(16)	(5)	(12)	(6)	(13)
T_2 -10° Down		(17) 3.9-380	(3) 3.2-414				(7)	(14)
T_3 +16° Up			(4) 3.4-381				(8)	(15)

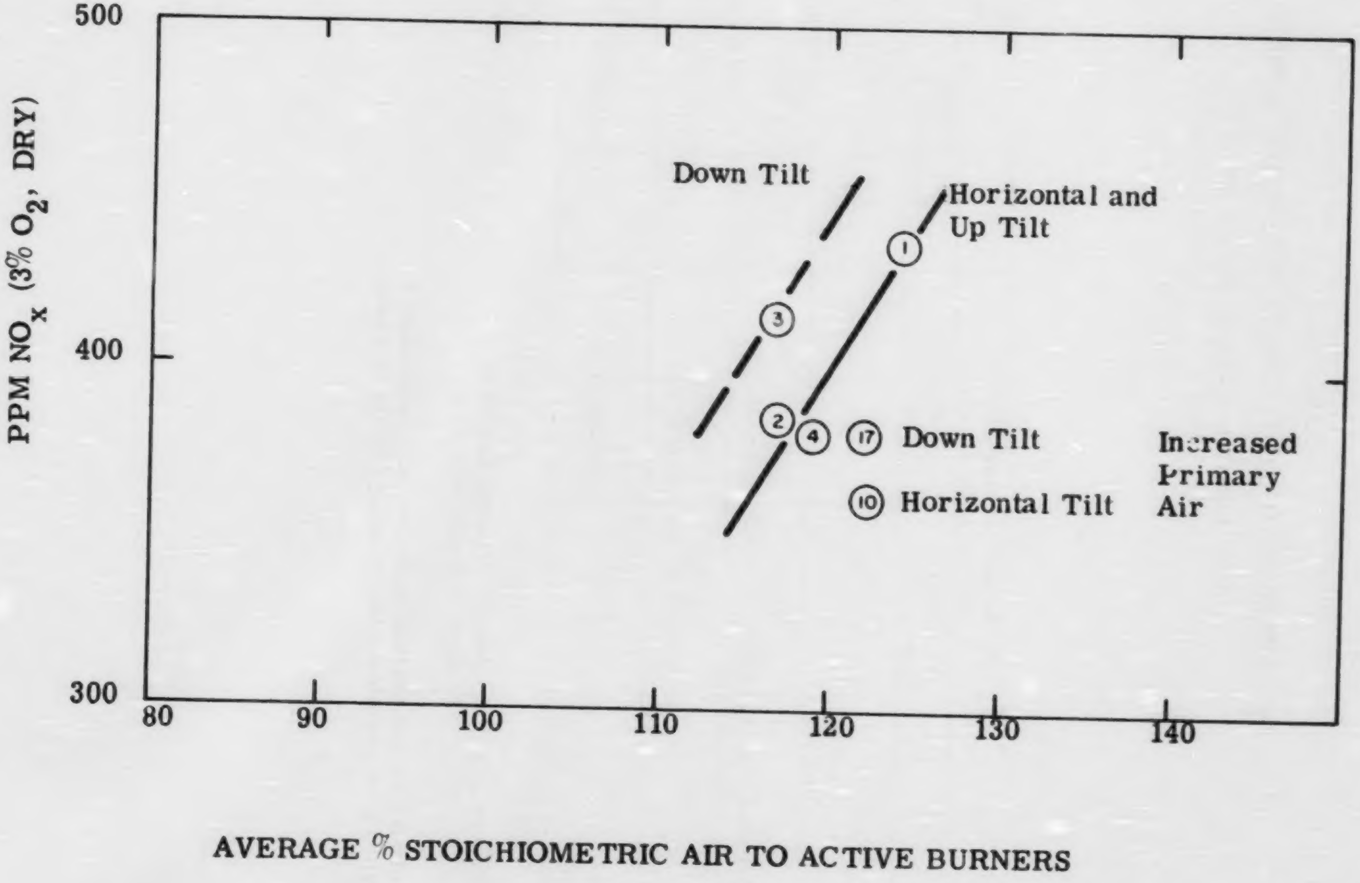
* Primary Air: P_1 Normal Primary Air Flow
P_2 High Primary Air Flow

** Pulverizer mechanical problems and maintenance schedules prevented the running of these tests.

FIGURE 6-20

PPM NO_x (3% O_2, DRY) VS %
STOICHIOMETRIC AIR TO ACTIVE BURNERS

(DAVE JOHNSTON STATION, BOILER No. 4)



directional air vanes. Normal position is 15° below horizontal for the air vanes. During our tests baseline data were taken with the dampers in the normal position and "low NO_x" emission data were obtained with the dampers aligned either 15° below the normal position, in both front and rear burners, or the front directional vanes were set at 15° below the normal position, and the rear directional vanes 15° above it. Simulated "staged" firing, at reduced load levels, was attempted by opening up the secondary air registers on selected burners, so that the active burners were supplied with 80% of stoichiometric air.

Table 12, Appendix A contains a summary of the operating and emission data obtained from the 14 test runs completed in Big Bend No. 2 boiler. The experimental design with average % oxygen and ppm NO_x data for each run is shown in Table 6-16. A diagram of the mill-burner configeration is also shown at the bottom of table to aid in visualizing the "simulated" staged firing patterns.

The NO_x emission results obtained are shown in the least squares regression of Figure 6-21. Reducing the air to the burners from the normal level of 115% of stoichiometric to 107% decreased NO_x emissions from about 600 ppm at 370 MW to about 400 ppm, or a reduction of about one third. This decrease in NO_x with reducing excessing air is steeper than that generally observed in wall and tangentially fired units. On the other hand, it should be noted that the "baseline" NO_x emission was determined at a load reduction of 18%, compared with maximum continuous rating. Further load reduction produced, as expected, further decreases in NO_x.

"Staged" firing, which in this instance was quite different from the normal pattern of staging burners, produced only a 10% reduction in NO_x at the low load of 230 MW, as shown in Figure 6-21. It was interesting to note that NOx levels were consistently lower at the ends of the furnace compared to its middle as shown in Figure 6-22.

The best NO_x reductions were obtained with front wall directional air vanes tilted 15° down, and rear vanes tilted 15° up from their normal alignment. Flyash reinjection had no significant effect on NO_x emissions.

Further testing is required with coal-fired turbo-furnace boilers to define optimum operation for NO_x control, taking into account steam temperature control, slagging, and potential furnace water-tube corrosion problems.

TABLE 6-16

EXPERIMENTAL DESIGN WITH % O_2 AND PPM NO_x (3% O_2 BASIS)

(Big Bend Station, Boiler No. 2)

	L_1 370 - 385 MW		L_2 300 MW		L_3 225 - 230 MW	
	A_1 Normal Excess Air	A_2 Low Excess Air	A_1 Normal Excess Air	A_2 Low Excess Air	A_1 Normal Excess Air	A_2 Low Excess Air
T_1 Directional Vanes Front - 15° Rear - 15°	(1) Ash On 2.8-614 (2) Ash Off 2.8-587	(3) Ash Off 2.0-464	(11) Ash Off 2.5-397	(12) Ash Off 2.1-362		
T_2 Directional Vanes Front - 15° Rear - 15°	(4A) Ash On 2.8-547 (4B) Ash Off 2.9-558	(5) Ash Off 1.4-398	(9) Ash Off 2.9-378	(10) Ash Off 1.8-341	(6) Ash On 3.4-370 (20)* Ash Off 3.4-350	(21)** Ash Off 3.5-312 (22)*** Ash Off 3.5-312

* Run 20 B mill off, secondary air dampers closed on idle burners.

** Run 21 B mill off, secondary air dampers open on 1/2 idle burners.

*** Run 22 B mill off, secondary air dampers open on all idle burners.

** Mill Burner Configuration

Air Only Burners Shown by Arrows

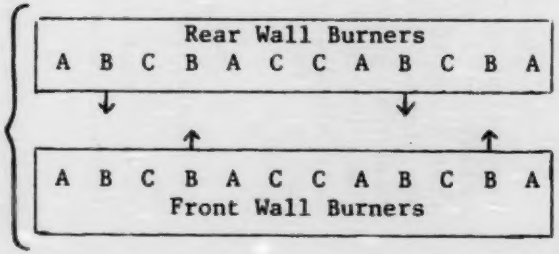


FIGURE 6-21

PPM NO$_x$ (3% O$_2$, DRY) VS % STOICHIOMETRIC AIR TO ACTIVE BURNERS

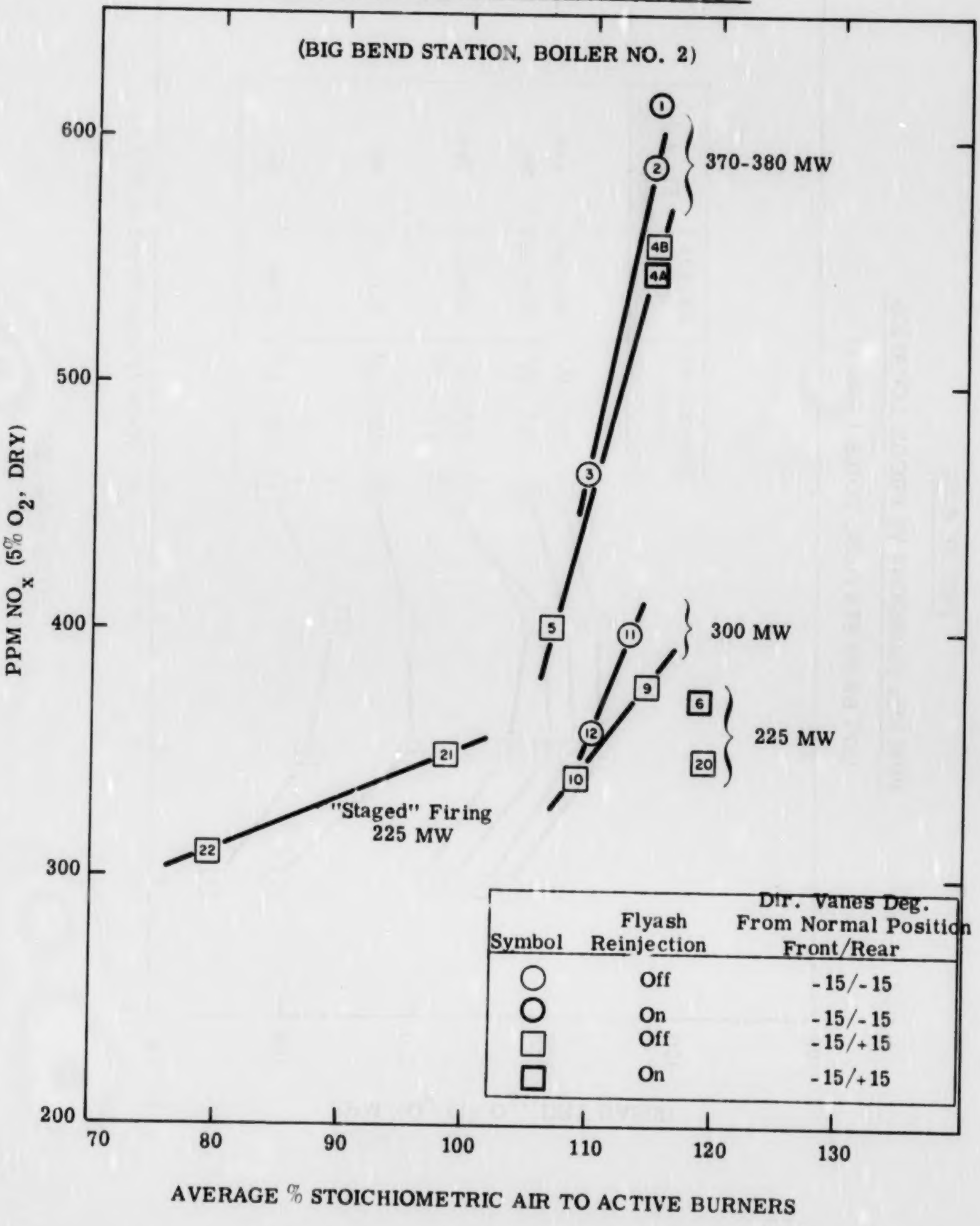
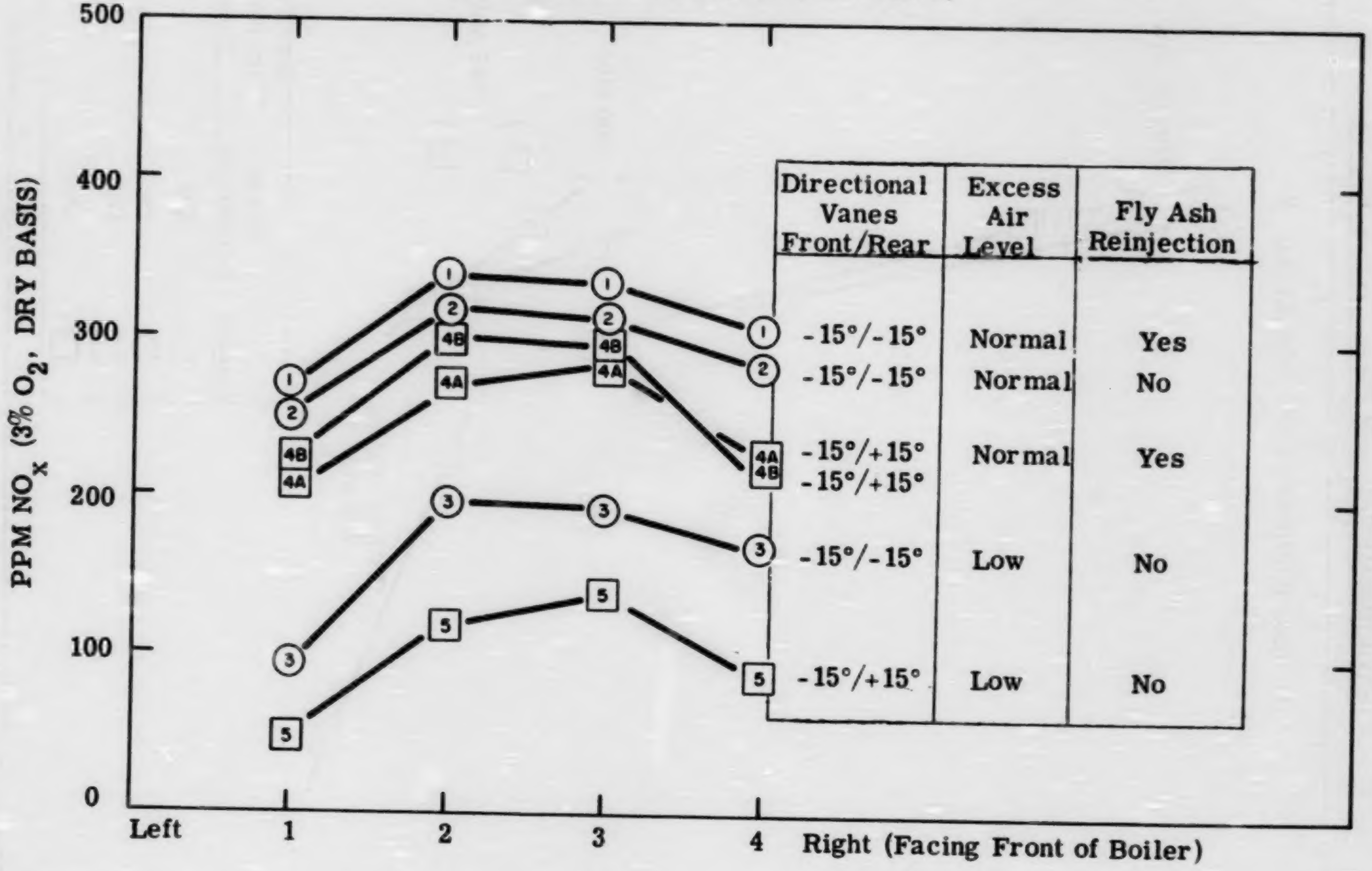


FIGURE 6-22

PPM NOx EMISSIONS VS PROBE LOCATION

(BIG BEND STATION, BOILER NO. 2)



Directional Vanes Front/Rear	Excess Air Level	Fly Ash Reinjection
-15°/-15°	Normal	Yes
-15°/-15°	Normal	No
-15°/+15° -15°/+15°	Normal	Yes
-15°/-15°	Low	No
-15°/+15°	Low	No

PROBE NUMBER

6.1.2 Particulate Emission Results

The results of the particulate emission tests obtained on this program, summarized in Table 6-17, are internally consistent and appear to be reliable within the limitations of this type of testing. As mentioned in section 4.2.2, the objective of this work was to obtain sufficient particulate loading information to determine the potential adverse side effects of "low NO_x" firing techniques on particulate emissions by comparing measurements of total quantities and percent unburned carbon with similar data obtained under normal or baseline operating conditions. The differences in emission values and particulate carbon content between baseline and "low NO_x" operation summarized in Table 6-17 afford an assessment of the adverse affect of "low NO_x" firing on a given boiler.

Not unexpectedly, some "side effects" did develop with "low NO_x" firing. Total quantities of particulate tend to increase but not significantly and the consequences appear to be relatively minor. This trend would have an adverse effect on the required collection efficiency of electrostatic precipitators to meet present Federal emission standards, but the increases in efficiency indicated by these limited tests appear to be quite small.

Another side-effect of "low NO_x" operation is that on carbon losses. Carbon content of the particulates with "low NO_x" operation are shown in Table 6-17 to increase significantly for front wall and horizontally opposed fired boilers. The data are quite scattered, and these increases do not appear to be directly related to the change in emissions with "low NO_x" firing technqiues or other boiler operating variables. For example, the tests on boiler No. 4 at the Four Corners Station of Arizona Public Service Company, a horizontally opposed fired boiler burning western coal, showed marginal decreases in particulate carbon content. Surprisingly, there is some evidence that "low NO_x" firing techniques for tangentially fired boilers may decrease carbon losses significantly. It also appears that "low NO_x" operation may decrease carbon losses for boilers fired with Western coals. Such improvements, however, would not be substantial since unburned combustible losses with these coals are already low. The effect of these changes in combustibles on boiler efficiency is discusssed in Section 6.1.4 and are shown to be relatively insignificant.

It is important to note that no major adverse side effects appear to result from "low NO_x" firing with regard to particulate emissions. Additional test data on a variety of boiler types are required to firm up on these conclusions. It would also be desirable to include investigation into potential changes in particle size distribution and the resultant effect on precipitator collection efficiency in the scope of future tests. Potential changes in fly ash resistivity with respect to precipitator performance is another area for investigation.

TABLE 6-17

PARTICULATE EMISSION TEST RESULTS

Utility	Test No.	Firing Condition	Av. Gr/SCF @ Std. Cond.	lb./10^6 BTU	Grams/ 10^6 cal.	Reqd. Efficiency To Meet 0.1 lb/ 10^6 BTU	% Carbon on Particulate	Coal Ash Wet, %	HHV BTU/lb. Wet
TVA	1A	Base	2.68	4.65	8.37	97.85	6.29	15.87	11,452
	1B	Base	4.62	7.89	14.20	98.73	5.90	18.39	11,477
	10-C-1	Low NO_x	2.32	3.84	6.91	97.40	10.55	11.50	11,918
	10-C-3	Low NO_x	3.36	5.62	10.12	98.22	8.46	14.38	11,231
	26-A-1	Low NO_x	3.13	5.10	9.18	98.04	12.40	15.39	10,961
Georgia Power Company	1C	Base	1.83	3.03	5.45	96.70	5.50	12.05	12,310
	1D	Base	1.86	3.20	5.76	96.88	3.17	9.72	12,589
	1E	Base	2.26	3.84	6.91	97.40	2.80	8.58	12,121
	1G	Low NO_x	2.47	3.71	6.68	97.30	6.73	11.28	12,200
	1H	Low NO_x	2.60	3.92	7.06	97.45	11.82	8.43	12,574
	52D	Low NO_x	2.00	3.12	5.62	86.79	9.98	10.3	11,178
	52E	Low NO_x	2.65	4.14	7.45	97.58	7.41	11.86	11,887
Arizona Public Service Co.	1E	Base	4.52	7.65	13.77	98.69	0.69	21.92	8,821
	1F	Base	5.36	8.91	16.04	98.88	0.53	21.96	8,811
	12A	Low NO_x	4.87	8.38	15.08	98.81	0.18	23.13	8,913
	12B	Low NO_x	3.26	5.59	10.06	98.21	0.46	21.12	8,915
Alabama Power Company	42A	Base	1.17	2.00	3.60	95.00	24.23	4.89	12,706
	42B	Base	3.08	5.14	9.25	98.05	25.83	4.86	12,641
	19A	Low NO_x	3.31	5.57	10.03	98.20	14.75	10.68	11,918
	19B	Low NO_x	3.32	5.49	9.88	98.18	18.77	8.82	12,720
Utah Power & Light Co.	23	Base	0.448	0.76	1.37	86.91	22.62	8.16	10,293
	23	Base	0.301	0.51	0.92	80.55	22.62	8.16	10,293
	25	Base	0.752	0.44	0.81	77.73	4.44	6.78	10,273
	26	Base	0.800	1.48	2.59	93.04	1.80	8.10	9,992
Gulf Power Co.	1	Base	2.54	4.34	7.81	97.70	5.08	10.20	11,186
	26B	Low NO_x	3.82	6.45	11.61	98.45	8.15	12.04	11,282

6.1.3 Accelerated Corrosion Probing Results

As mentioned in Section 4.2.3, corrosion probes were installed in the furnaces of the boilers tested by inserting them through available openings closest to the areas of the furnace susceptible to corrosion. Probe locations are indicated in Figure 6-23. Prior to installing the probes in the test furnace, the probes were preapred by mild acid pickling, pre-weighing the coupons, and screwing them onto the probes along with the necessary thermocouples. Each probe was then exposed to the furnace atmosphere prevailing for the particular type of operation desired for approximately 300 hours at coupon temperatures of about 875°F in order to accelerate corrosion. After exposure, furnace slag was cleaned off and saved for future analyses, and the coupons were carefully removed from the probes. In the laboratory the coupons were cleaned ultrasonically with fine glass beads to the base metal, and re-weighed to determine the weight loss.

Total weight loss data were converted to corrosion rates on a mils per year basis, using the combined inner and outer coupon areas, coupon material density, and exposure time. Wastage was found to have occurred on the internal surfaces of some of the coupons, possibly because of the oxidation of the hot metal by the cooling air. Attempts were made to determine "internal" and "external" corrosion rates by selective cleaning and weight loss determinations, but the results were found to be more consistent and reliable on an overall basis.

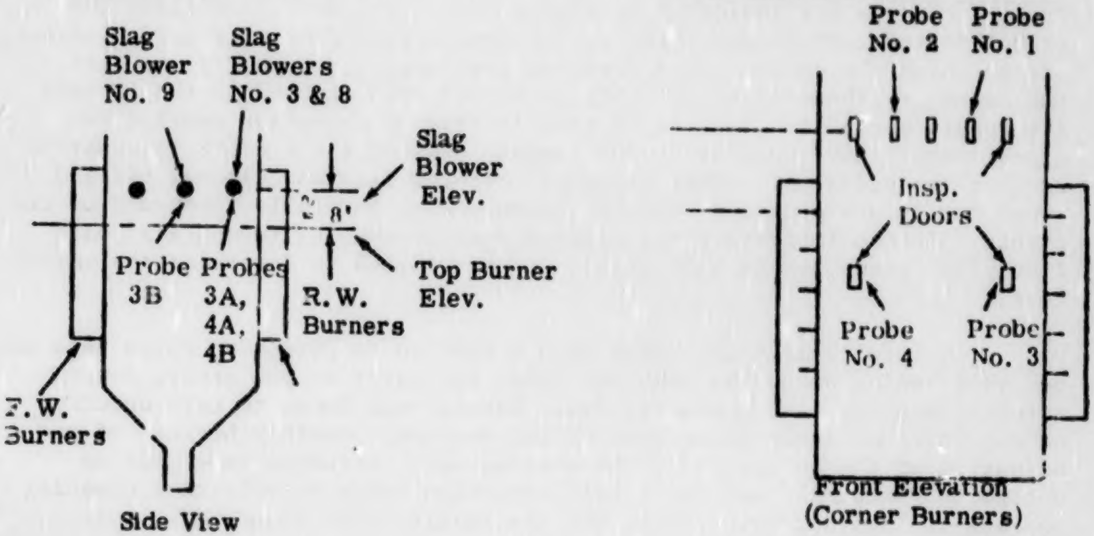
Corrosion rates have been determined for 40 coupons installed on 20 probes (2 coupons/probe), in boilers at four different generating stations as listed in section 4.2.3. Corrosion data obtained are tabulated in Table 6-18.

Although there is some scatter in the data obtained, as shown in Table 6-18, most of the information is quite consistent. A major finding of these tests is that no major differences in corrosion rates have been observed for coupons exposed to "low NO_x" conditions compared to those subjected to normal operation. In fact, for some probes the corrosion rates were found to be even lower than for "low NO_x" exposure.

Since corrosion rates have been deliberately accelerated in this study in order to develope "measurable" corrosion rates in a short time period, measured rates, as expected, are much higher than the normal wastage of actual furnace wall tubes. In future tests, coupons should not be acid-pickled to remove oxide coatings, and coupon exposure temperatures should be maintained lower for a closer approximation of actual tube wastage.

FIGURE 6-23

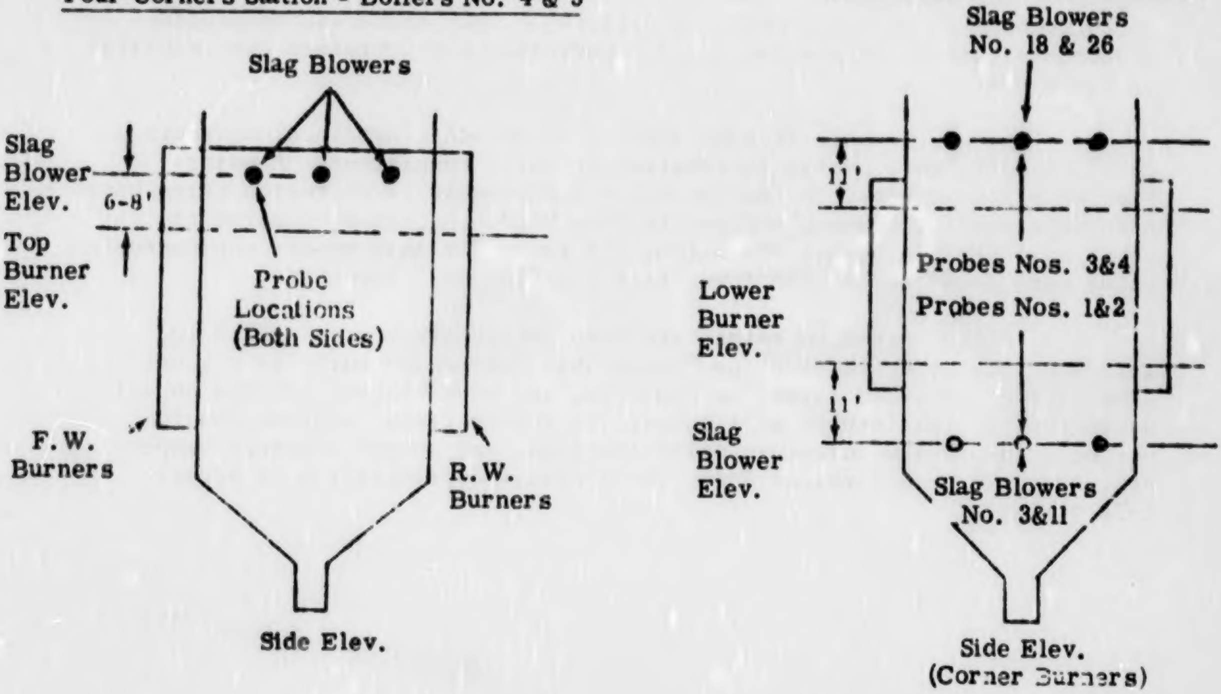
FURNACE CORROSION PROBE LOCATIONS



Georgia Power
Harllee Branch Station
Boilers No. 3 & 4

Utah Power and Light Company
Naughton Station Boiler No. 3

Slag Blower No. 9
Slag Blowers No. 3 & 8
Slag Blower Elev.
8'
Probe 3B
Probes 3A, 4A, 4B
R.W. Burners
Top Burner Elev.
F.W. Burners
Side View
Probe No. 2
Probe No. 1
Insp. Doors
Probe No. 4
Probe No. 3
Front Elevation (Corner Burners)



Arizona Public Service Company
Four Corners Station - Boilers No. 4 & 5

Alabama Power Company
Barry Station - Boiler No. 4

Slag Blowers
Slag Blower Elev.
6-8'
Top Burner Elev.
Probe Locations (Both Sides)
F.W. Burners
R.W. Burners
Side Elev.
Slag Blowers No. 18 & 26
11'
Probes Nos. 3&4
Probes Nos. 1&2
Lower Burner Elev.
11'
Slag Blower Elev.
Slag Blowers No. 3&11
Side Elev. (Corner Burners)

TABLE 6-18

ACCELERATED CORROSION RATE DATA

Boiler	Firing Condition	Corrosion Rate,* Mils/Yr
Georgia Power, Harllee Branch No. 4	Baseline	75 72
Georgia Power, Harllee Branch No. 4	Baseline	26 48
Georgia Power, Harllee Branch No. 3	Low NO_x	28 122
Georgia Power, Harllee Branch No. 3	Low NO_x	76 155
Utah P&L, Naughton No. 3	Baseline	124 65
Utah P&L, Naughton No. 3	Baseline	43 47
Utah P&L, Naughton No. 3	Baseline	16 24
Utah P&L, Naughton No. 3	Baseline	25 25
Arizona Public Service, Four Corners No. 4	Baseline	157 59
Arizona Public Service, Four Corners No. 4	Baseline	45 59
Arizona Public Service, Four Corners No. 5	Low NO_x	61 160
Arizona Public Service, Four Corners No. 5	Low NO_x	25 24

TABLE 6-18 (Cont'd)

ACCELERATED CORROSION RATE DATA

Boiler	Firing Condition	Corrosion Rate*, Mils/Yr
Alabama Power, Barry No. 4	Baseline	34 24
Alabama Power, Barry No. 4	Baseline	17 18
Alabama Power, Barry No. 4	Baseline	11 13
Alabama Power, Barry No. 4	Baseline	16 16
Alabama Power, Barry No. 4	Low NO_x	32 26
Alabama Power, Barry No. 4	Low NO_x	41 52
Alabama Power, Barry No. 4	Low NO_x	77 87
Alabama Power, Barry No. 4	Low NO_x	13 18

---

* Paired corrosion rate values obtained on two coupons exposed on the same probe.

Much more data are obviously required to resolve the question of furnace tube corrosion under "low NO_x" firing conditions. The limited data obtained in this study should be helpful in providing evidence that furnace tube corrosion may not necessarily be a severe adverse side-effect of low NO_x firing. Long term "low NO_x" tests using corrosion probes and the measurement of actual furnace wall tube corrosion rates are needed to answer these questions.

6.1.4 Boiler Performance Results

The side effects of "low NO_x" combustion modifications on boiler performance were investigated and evaluated for each major test where particulate runs were made under full load baseline and optimum "low NO_x" conditions. Pertinent control room board data and other information representing each test run were recorded and boiler efficiency was calculated in accordance with the ASME Steam Generating Units, Power Test Codes using the Abbreviated Efficiency Test, heat loss method. Calculations were based on the assumption that combustibles in the bottom ash slag was zero and unmeasured losses were 0.5 percent. An example of typical performance data and the calculations made are shown in the ASME test forms of Tables 6-19 and 6-20.

The boiler efficiency calculated for each test is tabulated in Table 6-21 along with other pertinent boiler performance information. Differences in calculated boiler efficiency between baseline and "low NO_x" tests provide a comparison of any debit or credit accruing to "low NO_x" emission combustion operations. However, such comparisons are confounded by other factors such as boiler load during the test run, the percent ash of the coal fired during the test and the carbon content of the particulate. In general, boiler efficiency increases with load and decreases with increases in coal ash or unburned combustible content of the particulate emissions. As discussed in section 6.1.2, particulate carbon content tends to increase under "low NO_x" operation for front wall and horizontally opposed fired boilers. The data, however, are quite scattered and these increases do not appear directly related to the change in emissions with "low NO_x" firing techniques. For example, the tests at the Four Corners Station, unit No. 4 (a horizontally opposed boiler fired with Western coal) showed marginal decreases in particulate carbon content at the same relative load and coal ash content.

The overall conclusion from these performance data is that only negligible differences in boiler efficiency occur with "low NO_x" firing compared to baseline operation. Stated another way, it appears that there are no significant performance debits with regard to boiler efficiency under "low NO_x" emission operation. More performance data are needed on all types of boilers to substantiate these important preliminary findings.

TABLE 6-19

SUMMARY SHEET

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

PTC 4.1-a (1964)

TEST NO. 1A BOILER NO. 6 DATE 4-18-72
OWNER OF PLANT TVA LOCATION Widows Creek
TEST CONDUCTED BY Esso Research & Engineering Co. OBJECTIVE OF TEST Boiler Performanc DURATION 4 Hrs.
BOILER, MAKE & TYPE B&W Radiant
STOKER, TYPE & SIZE RATED CAPACITY 125 MW
PULVERIZER, TYPE & SIZE Type E
FUEL USED Bituminous Coal MINE BURNER, TYPE & SIZE
COUNTY STATE SIZE AS FIRED

PRESSURES & TEMPERATURES

1	STEAM PRESSURE IN BOILER DRUM	psia	
2	STEAM PRESSURE AT S. H. OUTLET	psia	
3	STEAM PRESSURE AT R. H. INLET	psia	
4	STEAM PRESSURE AT R. H. OUTLET	psia	
5	STEAM TEMPERATURE AT S. H. OUTLET	F	
6	STEAM TEMPERATURE AT R. H. INLET	F	
7	STEAM TEMPERATURE AT R. H. OUTLET	F	
8	WATER TEMP. ENTERING (ECON.)(BOILER)	F	
9	STEAM QUALITY % MOISTURE OR P. P. M.		
10	AIR TEMP. AROUND BOILER (AMBIENT)	F	
11	TEMP. AIR FOR COMBUSTION (This is Reference Temperature) †	F	88
12	TEMPERATURE OF FUEL	F	
13	GAS TEMP. LEAVING (Boiler) (Econ.) (Air Htr.)	F	372
14	GAS TEMP. ENTERING AH (If conditions to be corrected to guarantee)	F	

UNIT QUANTITIES

15	ENTHALPY OF SAT. LIQUID (TOTAL HEAT)	Btu/lb	
16	ENTHALPY OF (SATURATED)(SUPERHEATED) STM.	Btu/lb	
17	ENTHALPY OF SAT. FEED TO (BOILER) (ECON.)	Btu/lb	
18	ENTHALPY OF REHEATED STEAM R.H. INLET	Btu/lb	
19	ENTHALPY OF REHEATED STEAM R. H. OUTLET	Btu/lb	
20	HEAT ABS/LB OF STEAM (ITEM 16 – ITEM 17)	Btu/lb	
21	HEAT ABS/LB R.H. STEAM (ITEM 19 – ITEM 18)	Btu/lb	
22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb	15.87
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb	912.1
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb	0.66
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb	11.6

HOURLY QUANTITIES

26	ACTUAL WATER EVAPORATED	lb/hr	
27	REHEAT STEAM FLOW	lb/hr	
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr	
29	TOTAL HEAT INPUT $\frac{(\text{Item 28} \times \text{Item 41})}{1000}$	kB/hr	
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr	
31	TOTAL HEAT OUTPUT $\frac{(\text{Item 26} \times \text{Item 20}) + (\text{Item 27} \times \text{Item 21})}{1000}$ + Item 30	kB/hr	

FLUE GAS ANAL. (BOILER)(ECON) (AIR HTR) OUTLET

32	CO_2	% VOL	14.4
33	O_2	% VOL	3.3
34	CO	% VOL	0.04
35	N_2 (BY DIFFERENCE)	% VOL	82.26
36	EXCESS AIR	%	

FUEL DATA

	COAL AS FIRED PROX. ANALYSIS	% wt		OIL	
37	MOISTURE	5.4	51	FLASH POINT F*	
38	VOL MATTER		52	Sp. Gravity Deg. API*	
39	FIXED CARBON		53	VISCOSITY AT SSU* BURNER SSF	
40	ASH		44	TOTAL HYDROGEN % wt	
	TOTAL		41	Btu per lb	
41	Btu per lb AS FIRED	11452			
42	ASH SOFT TEMP.* ASTM METHOD				

	COAL OR OIL AS FIRED ULTIMATE ANALYSIS			GAS	% VOL
			54	CO	
43	CARBON	67.27	55	CH_4 METHANE	
44	HYDROGEN	4.29	56	C_2H_2 ACETYLENE	
45	OXYGEN		57	C_2H_4 ETHYLENE	
46	NITROGEN		58	C_2H_6 ETHANE	
47	SULPHUR	0.77	59	H_2S	
40	ASH	15.87	60	CO_2	
37	MOISTURE		61	H_2 HYDROGEN	
	TOTAL			TOTAL	
				TOTAL HYDROGEN % wt	

	COAL PULVERIZATION				
48	GRINDABILITY INDEX*		62	DENSITY 68 F ATM. PRESS.	
49	FINENESS % THRU 50 M*		63	Btu PER CU FT	
50	FINENESS % THRU 200 M*		41	Btu PER LB	

64 INPUT-OUTPUT EFFICIENCY OF UNIT % $\frac{\text{ITEM 31} \times 100}{\text{ITEM 29}}$

	HEAT LOSS EFFICIENCY	Btu/lb A. F. FUEL	% of A. F. FUEL
65	HEAT LOSS DUE TO DRY GAS		6.90
66	HEAT LOSS DUE TO MOISTURE IN FUEL		0.55
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2		3.95
68	HEAT LOSS DUE TO COMBUST. IN REFUSE		1.26
69	HEAT LOSS DUE TO RADIATION		0.002
70	UNMEASURED LOSSES		0.5
71	TOTAL		13.16
72	EFFICIENCY = (100 – Item 71)		86.84

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* Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

TABLE 6-20

PTC 4.1-b (1964)

CALCULATION SHEET

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

Revised September, 1965

OWNER OF PLANT TVA   TEST NO. 1A   BOILER NO. 6   DATE 4-18-72

30 HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × $\left[\dfrac{\overset{\text{ITEM 15}}{\ldots\ldots} - \overset{\text{ITEM 17}}{\ldots\ldots}}{1000}\right]$ = ... kB/hr

24 *If impractical to weigh refuse, this item can be estimated as follows*

DRY REFUSE PER LB OF AS FIRED FUEL = $\dfrac{\text{\% ASH IN AS FIRED COAL}}{100 - \text{\% COMB. IN REFUSE SAMPLE}}$

CARBON BURNED PER LB AS FIRED FUEL = $\dfrac{\overset{\text{ITEM 43}}{67.27}}{100} - \left[\dfrac{\overset{\text{ITEM 22}}{0.1587} \times \overset{\text{ITEM 23}}{912.1}}{14{,}500}\right] = 0.66$

NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.

25 DRY GAS PER LB AS FIRED FUEL BURNED = $\dfrac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)} \times \left(\text{LB CARBON BURNED PER LB AS FIRED FUEL} + \dfrac{3}{8}S\right)$

$$= \frac{11 \times \overset{\text{ITEM 32}}{14.4} + 8 \times \overset{\text{ITEM 33}}{3.3} + 7\left(\overset{\text{ITEM 35}}{82.26} + \overset{\text{ITEM 34}}{0.04}\right)}{3 \times \left(\overset{\text{ITEM 32}}{14.4} + \overset{\text{ITEM 34}}{0.04}\right)} \times \left[\overset{\text{ITEM 24}}{0.66} + \frac{\overset{\text{ITEM 47}}{0.77}}{267}\right] = 11.6$$

36 EXCESS AIR† = $100 \times \dfrac{O_2 - \dfrac{CO}{2}}{.2682N_2 - \left(O_2 - \dfrac{CO}{2}\right)} = 100 \times \dfrac{\text{ITEM 33} - \dfrac{\text{ITEM 34}}{2}}{.2682\,(\text{ITEM 35}) - \left(\text{ITEM 33} - \dfrac{\text{ITEM 34}}{2}\right)}$ = ...

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	$\frac{\text{LOSS}}{\text{HHV}} \times 100 =$	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL $\times C_p \times (t_{lvg} - t_{air})$ = Unit $\overset{\text{ITEM 25}}{11.6} \times 0.24\ \overset{(\text{ITEM 13}) - (\text{ITEM 11})}{372 - 88}$ = 790	790	$\frac{65}{41} \times 100 =$	6.90
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = $\frac{\overset{5.4}{\text{ITEM 37}}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) 1227.9 − (ENTHALPY OF LIQUID AT T ITEM 11)] 56 = 63.3	63.3	$\frac{66}{41} \times 100 =$	0.55
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = 9 × $\frac{\overset{4.29}{\text{ITEM 44}}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) 1227.9 − (ENTHALPY OF LIQUID AT T ITEM 11)] 56 = 452.5...	452.5	$\frac{67}{41} \times 100 =$	3.95
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = $\overset{\text{ITEM 22}}{0.1587} \times \overset{\text{ITEM 23}}{912.1}$ = 144.8	144.8	$\frac{68}{41} \times 100 =$	1.26
69	HEAT LOSS DUE TO RADIATION* = $\frac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL} - \text{ITEM 28}}$	0.2	$\frac{69}{41} \times 100 =$	0.002
70	UNMEASURED LOSSES **	......	$\frac{70}{41} \times 100 =$	0.5
71	TOTAL	......	......	13.16
72	EFFICIENCY = (100 − ITEM 71)	......	......	86.84

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† For rigorous determination of excess air see Appendix 9.2 – PTC 4.1-1964

* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964

** Unmeasured losses listed in PTC 4.1 but not tabulated above may by provided for by assigning a mutually agreed upon value for Item 70.

TABLE 6-21

SUMMARY OF BOILER PERFORMANCE CALCULATIONS

Company, Station, Boiler No.	Firing Mode	Test No.	Load, MW	% O_2	NO_x, ppm (3% O_2)	Coal, % Ash	% Carbon on Particulate	Boiler Efficiency
Tennessee	Baseline	1A	125	3.3	669	15.87	6.29	86.8
Valley	Baseline	1B	128	3.6	656	18.39	5.9	86.2
Authority								
Widows Creek,	Low NO_x	10-C-1	120	3.0	343	11.32	10.55	86.7
No. 6	Low NO_x	10-C-3	125	3.3	397	14.38	8.46	86.5
	Low NO_x	26-A-1	97	2.8	299	15.39	12.40	85.9
Georgia	Baseline	1C	490	3.0	688	12.05	5.5	90.0
Power	Baseline	1D	488	3.7	711	9.72	3.17	90.2
Harllee	Baseline	1E	483	3.0	745	8.58	2.8	90.4
Branch, No. 3								
	Low NO_x	1G	478	1.2		11.28	6.73	90.2
	Low NO_x	1H	463	1.3	472	8.43	11.82	90.0
	Low NO_x	52D	475	1.9	582	10.30	9.98	88.7
	Low NO_x	52E	465	2.0	565	11.87	7.41	89.5
Arizona Public	Baseline	1E	755	3.4	741	21.92	.69	88.2
Service	Baseline	1F	775	3.1	715	21.96	.53	88.6
Four Corners,								
No. 4	Low NO_x	12A	725	4.3	560	23.13	.18	88.8
	Low NO_x	12B	704	3.7	458	21.12	.46	89.1
Alabama Power	Baseline	42A	293	5.0	396	4.78	24.23	88.4
Company	Baseline	42B	283	4.5	370	4.85	25.83	88.6
Barry, No. 4								
	Low NO_x	19A	283	4.6	347	10.69	14.75	88.8
	Low NO_x	19B	255	4.3	288	8.84	18.77	88.3
Gulf Power	Baseline	1	320	3.6	902	10.2	5.08	88.5
Crist, No. 6								
	Low NO_x	26B	350	3.2	888	10.2	8.15	88.1

6.2 Oil Fired Boilers Converted from Coal to Oil Firing

As discussed in Section 2, short-term tests were made on six coal-to-oil converted boilers. The emission results obtained are presented in this section.

6.2.1 Front-Wall Fired Boilers

6.2.1.1 Deepwater, Boiler No. 3

Boiler No. 3 of Deepwater Station is a Babcock and Wilcox designed, front wall fired, single furnace boiler, with a maximum continuous rating of 313,000 pounds of steam per hour at 1350°F and 725 pounds per square inch pressure. It was installed in 1928 to fire pulverized coal, but has recently been converted to oil firing. There are six mechanically atomizing burners firing in a single row across the front wall of the furnace.

Table 6-22 summarizes operating and emission data for the eight test runs conducted on this boiler. Operating variables were gross load and excess air level. Gross load (includes turbine generators 3H and 3L which run on steam from both No. 3 and No. 5 boilers) was varied from full load of 57 MW down to 19 MW. Excess air was varied from normal operating level down to the lowest level that could be reached without excessive CO emissions (greater than 200 ppm), or a visible plume showing from the stack. It should be noted that the plume from the stack under normal excess air operation is almost invisible. Under low excess air test operation, the plume would show slight "efficiency" haze or occasional gray wisps of smoke. Average NO_x measurements are listed on both ppm NO_x (3% O_2, dry basis) and pounds NO_x (calculated as NO_2) per 10^6 Btu. Average % oxygen measurements are also shown for each test run. Each of the six sampling probes contained two gas sampling tubes that were positioned to provide samples from the centers of four equal areas of each of the three ducts between the economizer and air preheaters. During the test runs, one or two of the probes consistently produced 1 to 2% higher oxygen readings (lower CO_2 and NO_x readings) than did the other probes, indicating a possible 5 to 10% air leakage into the sampling system prior to sample pumps. Although inspection and checking of the complete sampling system from probes to pumps revealed no leaks, the consistency of the measurements taken from the other four or five probes, and the agreement of the NO_x measurements from all probes on a 3% O_2, dry basis does indicate that one and sometimes two probes were probably leaking. Therefore, the average % oxygen for each test run includes data from the four or five consistent probes, while the average ppm NO_x (3% O_2, dry basis) for each run is the average dilution-corrected NO_x measurement from all six probes.

TABLE 6-22

SUMMARY OF OPERATING AND EMISSION DATA

Atlantic City Electric

(Deepwater Station, Boiler No. 3)

Oil Firing

Boiler Operating Conditions				Flue Gas(1) Measurements			
Test Run	Gross(3) Load	Excess Air	Burner No. Firing Oil	Smoke Meter	$\%O_2$ (2)	PPM NO_X ($3\%O_2$, Dry Basis)	POUNDS NO_X Per 10^6 BTU (4)
	(MW)						
1	56.5	Normal	All	0.95	6.1	142	0.19
2	57	Low	All	1.0	5.0	118	0.16
3	39	Normal	2, 3, 4 & 5	0.8	5.9	133	0.18
4	39	Low	2, 3, 4 & 5	1.0	5.0	102	0.14
5	19	Normal	2 and 5	0.8	9.2	143	0.19
6	19	Low	2 and 5	0.9	8.5	108	0.14
7	32	Normal	2, 3 & 5	0.8	7.2	135	0.18
8	32	Low	2, 3 & 5	1.1	6.3	96	0.13

(1) Average of three 2-minute gas composites from 2 sample tubes per probe with 2 probes per duct and 3 ducts per boiler.

(2) Average boiler % oxygen calculated from probes 1, 2, 4 and 5 for test runs 1 and 2, and from probes 2 through 6 for test runs 3 through 8. ppm NO_X calculated from all 6 probes.

(3) Boilers No. 3 and 5 provide steam to two turbines. Gross load data represents the combined gross load of both turbines.

(4) Calculated as NO_2.

Table 6-23 indicates the experimental design of operating variables, with average flue gas measurements of % oxygen and ppm NO_x (3% O_2, dry basis) shown for each test run. Figure 6-24 is a plot of ppm NO_x emissions vs. % oxygen in the flue gas for the four gross load conditions tested, at normal and low excess air levels, respectively.

Baseline operation (test run No. 1), at full load with all six burners firing oil, produced a relatively low average emission level of 142 ppm NO_x (3% O_2, dry basis) or 0.19 pounds per 10^6 Btu. Reducing excess air by about 5% (to 5% O_2 in the flue gas from 6.1% O_2) resulted in a 17% reduction in NO_x emissions to 118 ppm (3% O_2, dry basis). At reduced loads, very similar results were achieved. At 39 MW gross load (four burners firing), normal excess air operation resulted in 133 ppm NO_x, and low excess air operation produced 102 ppm NO_x, or a reduction of 23%. At 33 MW gross load (three burners firing), normal excess air operation resulted in 135 ppm NO_x, while low excess air operation produced a 24% reduction in NO emissions to 96 ppm. At the minimum gross load of 19 MW, normal excess air operation (two burners firing), resulted in 143 ppm NO_x, while low excess air operation at this load produced 108 ppm NO_x emissions or a reduction of 29%.

Although the constant, relatively low NO_x emission levels over the wide range of total loads from full load to one-third load might appear to be inconsistent with normal experience on oil fired boilers, we believe they can be logically explained for this boiler. The heat released per square foot of heating surface at full load is relatively low in this old boiler installed in 1928, while the steam rate was only about 255,000 pounds per hour, or 80% of the full load designed rate of 313,000 pounds per hour. The fuel rate at each of the six firing burners was a relatively low 348 gallon per hour at full load (Boiler No. 9, for comparison, fired about 820 gallons of fuel oil per hour to give 286 ppm NO_x emissions at full load). As the load was reduced, the number of firing burners was proportionately decreased so that at 39, 32 and 19 MW the fuel rates per firing burner was maintained relatively constant at 386, 380 and 392 gallons per hour, respectively. Also at the highest fuel rate per burner at 19 MW load, the distance between firing burners increased to three times normal firing operation and the distance between furnance side walls and firing burners was double that for full load operating distances.

Table 6-24 summarizes the average flue gas component and temperature measurement for each of the eight test runs completed on Deepwater Station, Boiler No. 3. This unit had a baseline NO_x emission level of only 142 ppm (3% O_2, dry basis) at full load. Reduced load operation at normal excess air resulted in maintaining NO_x emission levels between 133 and 143 ppm. The fact that load had negligible effect on the NO_x emissions strongly suggests that the bulk of the NO_x was formed through the oxidation of fuel nitrogen.

FIGURE 6-24

PPM NO_x VS % O_2 MEASURED IN FLUE GAS

Atlantic City Electric

(Deepwater Station, Boiler No. 3)

Oil Firing

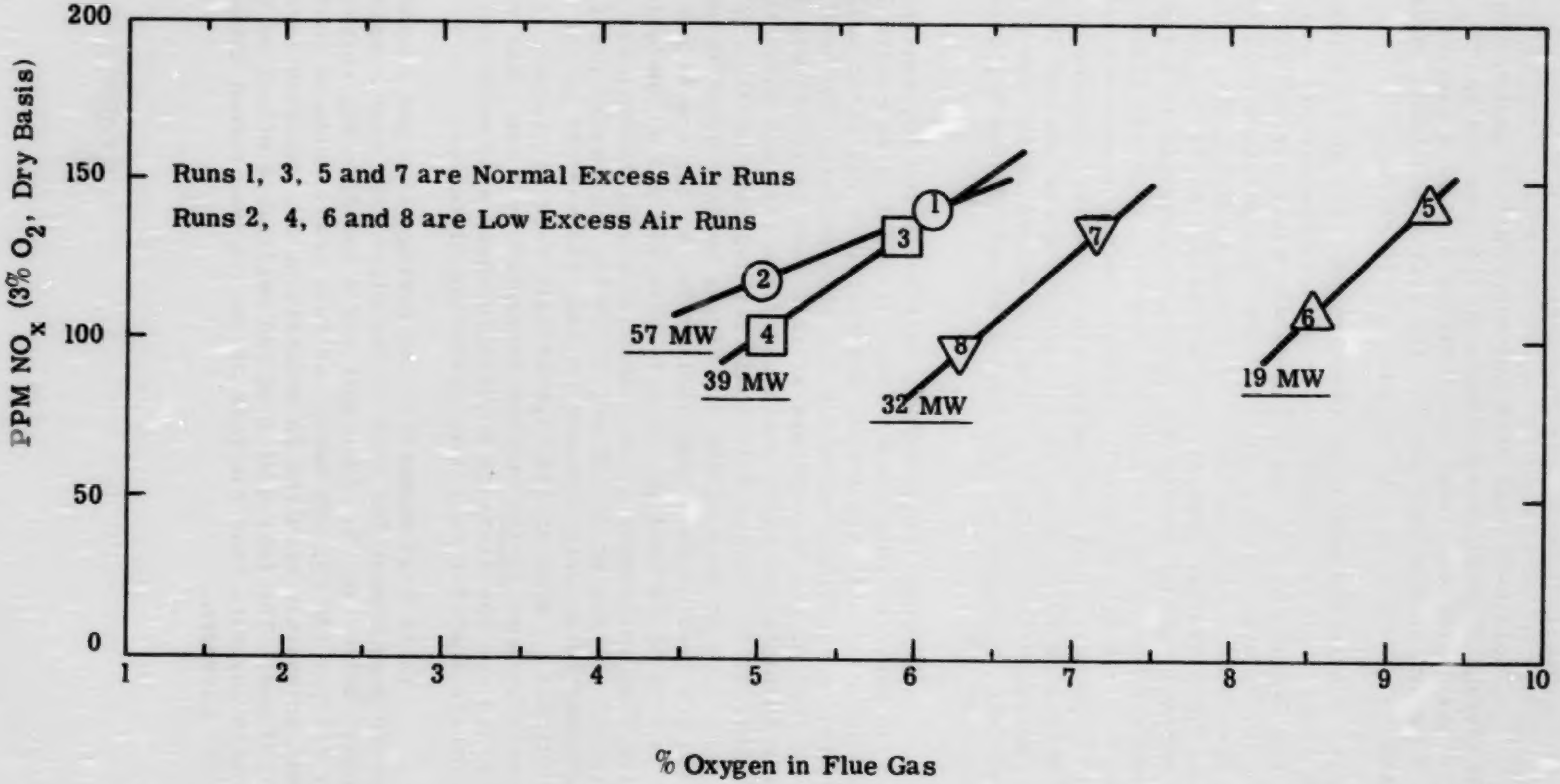


TABLE 6-23

EXPERIMENTAL DESIGN AND AVERAGE EMISSION MEASUREMENTS

Atlantic City Electric

(Deepwater Station, Boiler No. 3)

Oil Firing

	Gross Load (Boilers 3 and 5) and Number of Burners Firing			
	L_1 - 57 MW (6 Burners)	L_2 - 39 MW (4 Burners)	L_3 - 33 MW (3 Burners)	L_4 - 19 MW (2 Burners)
A_1 - Normal Excess Air	(1) 6.1% O_2 * 142 ppm NO_x	(3) 5.9% O_2 133 ppm NO_x	(7) 7.2% O_2 135 ppm NO_x	(5) 9.2% O_2 143 ppm NO_x
A_2 - Low Excess Air	(2) 5.0% O_2 118 ppm NO_x	(4) 5.0% O_2 102 ppm NO_x	(8) 6.3% O_2 96 ppm NO_x	(6) 8.5% O_2 108 ppm NO_x

* Each cell gives test run number, average % oxygen and ppm NO_x (3% C_2, dry basis).

TABLE 6-24

FLUE GAS EMISSION MEASUREMENTS AND TEMPERATURES

Atlantic City Electric
(Deepwater Station, Boiler No. 3)
Oil Firing

TEST RUN NO.	(2) GROSS LOAD (MW)	FLUE GAS MEASUREMENTS(1)					
		O_2	CO_2	NO_x	CO	HC	Temp.
		%	%	PPM @ 3%O_2	PPM @ 3%O_2	PPM @ 3%O_2	°F
1	56.5	6.1	9.9	142	67	--	601
2	57	5.0	10.5	118	81	--	616
3	39	5.9	9.5	133	56	1	491
4	39	5.0	10.1	102	349	1	477
5	19	9.2	7.2	143	53	1	417
6	19	8.5	7.4	108	74	2	399
7	32	7.2	8.7	135	55	1	454
8	32	6.3	9.3	96	141	1	448

(1) Average of three 2-minute gas composites from two sample tubes from each of 6 probes.

(2) Boilers No. 3 and 5 provide steam to two turbines. Gross load data represents the combined gross load of both turbines.

Low excess air operation successfully reduced NO_x emissions by 17 to 29%. These low emission levels are likely to be due to the relatively low heat release per unit volume of this furnace. Under all conditions tested, the NO_x emission levels were significantly below the EPA new source emission standard of about 225 ppm NO_x for oil fired boilers or 0.3 pounds NO_x per 10^6 Btu heat input.

6.2.1.2 Deepwater, Boiler No. 5

Boiler No. 5 of Deepwater Station is a Babcock and Wilcox designed, front wall fired, single furnace boiler, with a maximum continuous rating of 290,000 pounds of steam per hour at 1350°F and 725 pounds per square inch pressure. Installed in 1928 to fire pulverized coal, it has recently been converted to oil firing. The burner arrangement is similar to Boiler No. 3, with six mechanically atomizing oil burners arranged in a single row across the front wall of the furnance.

Boilers No. 3 and 5 feed main steam to high pressure Turbine Generator 3H (12 MW capacity). Boiler No. 5 reheats the exhaust steam from Turbine Generator 3H and feeds Turbine Generator 3L (42 MW capacity). Present operating practice results in firing boiler No. 5 with about 133% of the fuel burned in No. 3 boiler, resulting in Boiler No. 5 having a much higher heat release per unit furnace volume than No. 3.

Table 6-25 contains a summary of operating and emission data for the four test runs conducted on Boiler No. 5. In light of the low NO_x emission levels on sister unit No. 3, only baseline, normal and low excess air test runs 1 and 2 were planned for Boiler No. 5. However, test runs 1 and 2 produced NO_x emission levels close to the EPA new source standard of 225 ppm NO_x for oil fired boilers, and consequently, test runs 3 and 4 were conducted in an attempt to obtain lower NO_x emissions under full load operation.

Baseline NO_x emissions (test run No. 1) were 221 ppm (3% O_2, dry basis) or 0.29 pounds NO_x per 10^6 Btu under normal excess air, full load operation. Low excess air operation run No. 2 resulted in a 5% reduction in NO_x emission levels to 209 ppm. Fuel rates in gallons per hour per burner were about 33% higher (465 vs. 350) than baseline operation on sister unit No. 3, with its lower NO_x emission rate of 142 ppm. Test run No. 3 was conducted while firing with five burners equipped with large capacity tips, and with the air registers wide open on the idle burner (No. 3) to simulate low excess air, staged firing. However, the higher fuel firing rate per burner (540 vs. 465 gallons per hour), and single row of burner configuration resulted in an essentially baseline NO_x emission level of 225 ppm for test run No. 3. The last test run, No. 4, conducted at a 22% reduced oil firing rate of 365 vs. 465 gallons per burner-hour produced a 21% lowered NO_x emission level of 175 ppm, compared to the baseline emission level of 221 ppm. The steam rate on Boiler No. 3 was increased by about 40,000 pounds per hour to make up for the lowered steam rate of No. 5 boiler on run No. 4.

TABLE 6-25

SUMMARY OF OPERATING AND EMISSION DATA

Atlantic City Electric

(Deepwater Station, Boiler No. 5)

Oil Firing

Boiler Operating Conditions				Flue Gas Measurements(1)			
Test Run	Gross Load (MW)	Excess Air Level	No. of Burners Firing Oil	Smoke Meter	$\%O_2$	PPM NO_x ($3\%O_2$, Dry Basis)	POUNDS NO_x PER 10^6 BTU
1	56	Normal	6	0.62	4.2	221	0.29
2	56	Low	6	0.65	2.8	209	0.28
3	56	Low	5(2)	0.70	4.3	225	0.30
4	53	Low	6(2)	0.60	4.0	175	0.23

(1) Average boiler % oxygen calculated for probes 2, 3, 4 and 5. Ppm NO_x ($3\%O_2$, dry basis) calculated as arthmetric average of data for all 6 probes.

(2) Large capacity burner tips were used on test runs 3 and 4.

Boilers No. 3 and 5 utilize the same stack and there is some flexibility in adjusting the firing rate of the two boilers at full load. Consequently, there is probably a minimum stack NO_x emission rate obtained by judiciously balancing the heat load of the two boilers.

Table 6-26 contains average flue gas component measurements and temperatures for each of the four runs completed on Deepwater Station No. 5 boiler. Flue gas temperature, percent O_2, percent CO_2, ppm NO_x and ppm CO are shown. All data in ppm have all been corrected to a common 3% O_2, dry basis. Since the hydrocarbon instrument was inoperable during the test period, no HC measurements were obtained.

6.2.1.3 Deepwater, Boiler No. 8

Boiler No. 8 at the Deepwater Station is a Babcock and Wilcox designed, front wall fired, single furnace boiler, with a maximum continuous rating of 560,000 lb. steam per hour at 1005/1005°F superheat and reheat temperatures and 1520 psi design pressure. Installed in 1954 to fire pulverized coal, it has recently been converted to oil firing. The unit is of balanced draft construction with 16 burners arranged four high and three wide. Each burner is fired by a mechanical pressure atomizing oil gun of the return flow type.

Table 6-27 contains a summary of operating and emission data for the 25 test runs conducted on Boiler No. 8. Operating variables were gross load (data were collected at six different loads), excess air level, and firing pattern (seven different firing patterns were explored). Excess air was varied from normal operating level down to the lowest level that could be reached without excessive CO emissions (greater than 200 ppm), smoke meter indications greater than 1.0, or producing more than slightly visible stack plumes with periodic wisps of gray smoke. Under normal excess air operation, the stack plume is practically invisible. Under low excess air test operation, the plume often would show slight "efficiency" haze or occasional gray wisps of smoke. Boiler No. 8 is also limited in fan capacity and superheat and reheat control, making it difficult to operate at desired levels to achieve optimum low NO_x emissions with various staging patterns. Average ppm NO_x measurements (3% O_2, dry basis), pounds NO_x per 10^6 Btu and average % O_2 measurements are shown in Table 6-27 for each test run. Each of the four probes contained short, medium, and long gas sampling tubes that were positioned to provide samples from the centers of twelve equal duct areas located between the economizer and the air preheater inlet. Flue gas composition was remarkably uniform across the duct.

Table 6-28 summarizes the experimental design of operating variables, with average flue gas measurements of % oxygen and ppm NO_x (3% O_2, dry basis) shown for each run. Table 6-29 details the firing patterns employed during the NO_x tests, and is helpful in visualizing potential effects of the various firing configurations. Figure 6-25 is a plot of ppm NO_x vs. % oxygen in the flue gas for the seven firing patterns investigated under full load operations. Figure 6-26 is a plot of ppm NO_x vs. % O_2 in the flue gas for intermediate and low loads.

FIGURE 6-25

PPM NO_x VS % O_2 IN FLUE GAS

Atlantic City Electric
(Deepwater Station, Boiler No. 8)

Full Load

Oil Firing

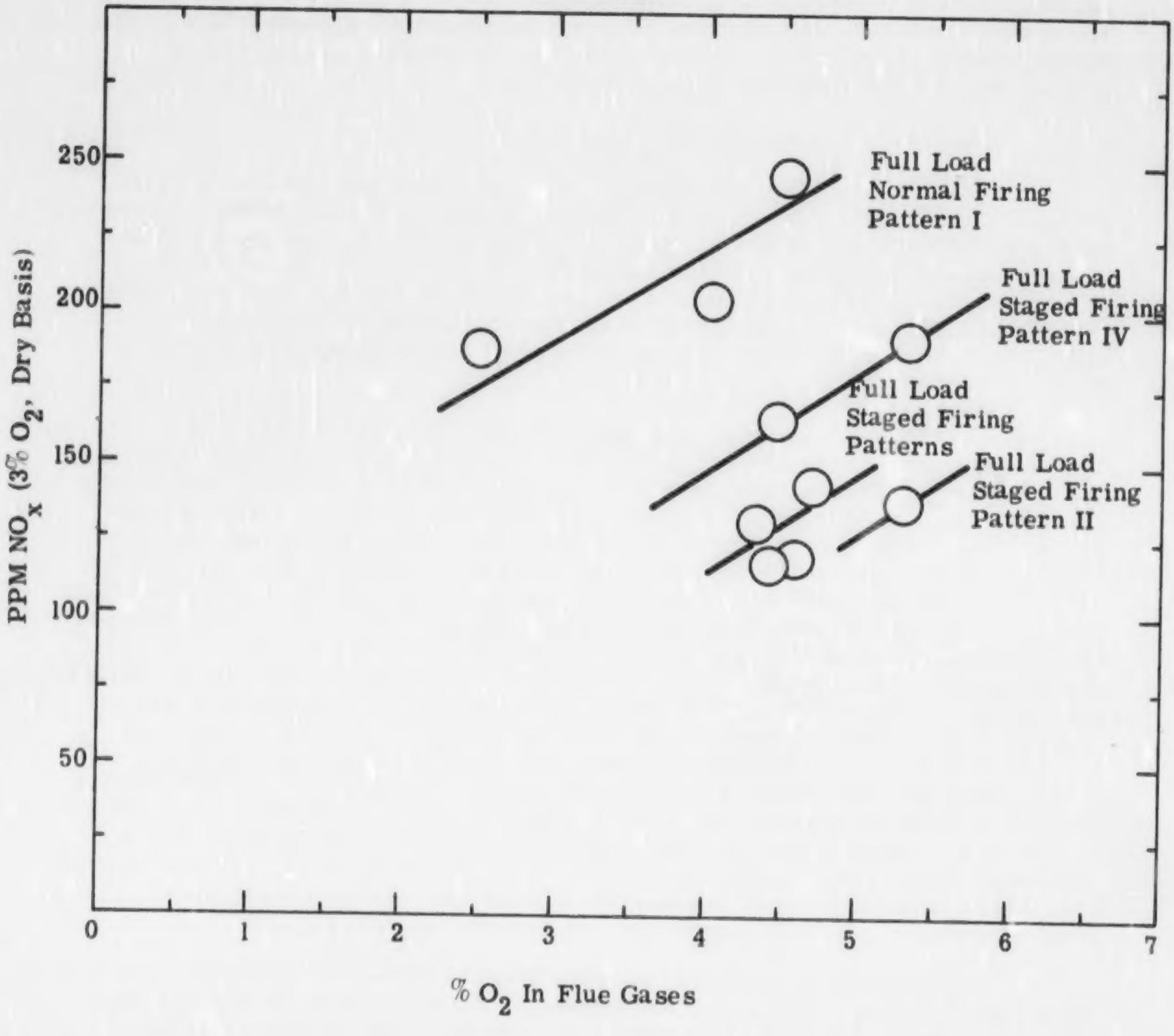


FIGURE 6-26

PPM NO_x VS % O_2 IN FLUE GAS

Atlantic City Electric

(Deepwater Station, Boiler No. 8)

Intermediate and Low Leads

Oil Firing

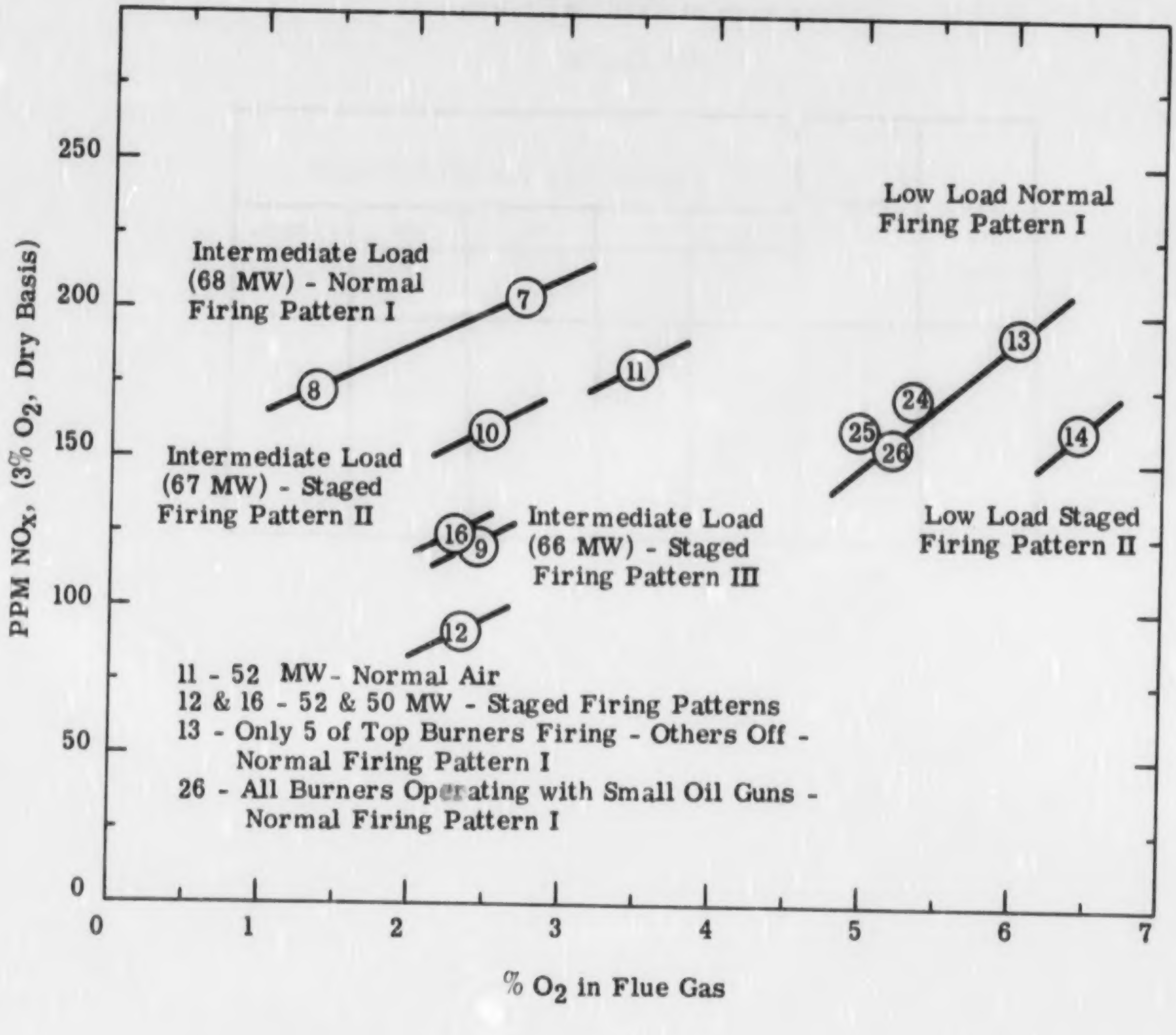


TABLE 6-26

FLUE GAS EMISSION MEASUREMENTS AND TEMPERATURES

Atlantic City Electric
(Deepwater Station, Boiler No. 5)
Oil Firing

TEST RUN NO.	GROSS LOAD (MW)	AVERAGE FLUE GAS MEASUREMENTS				
		O_2	CO_2	NO_x	CO	Temp.
		%	%	PPM ($3\%O_2$)	PPM ($3\%O_2$)	°F
1	56	4.2	11.9	221	55	569
2	56	2.8	12.5	209	84	547
3	56	4.3	11.7	225	79	561
4	53	4.0	11.8	175	83	527

TABLE 6-27

SUMMARY OF OPERATING AND EMISSION DATA

Atlantic City Electric

(Deepwater Station, Boiler No. 8)

Oil Firing

		Boiler Operating conditions			Flue Gas Measurements			
Date	Test Run No.	Gross Load MW	Excess Air Level	Firing Pattern (Burners on Air Only)	Smoke Meter	%O_2	PPM NO_X ($3\%O_2$, Dry)	POUNDS NO_X PER 10^6 BTU
5/16	1	83	Normal	Normal (None)	0.75	4.5	246	0.33
	2	81	Low	Normal (None)	1.0	2.3	188	0.25
5/17	1A	82.5	Normal	Normal (None)	0.7	4.1	208	0.28
	4	81	Low	Staged (84 Row)	0.8	5.2	136	0.18
	6A	82	Low	Staged (84S,84N,82C)	0.8	4.4	165	0.22
	5A	83	Normal	Staged (84S,84N,82C)	0.75	5.3	192	0.25
5/19	7	68	Normal	Normal (None)	0.75	5.5	204	0.27
	8	66	Low	Normal (None)	0.9	2.6	172	0.23
	9	66	Low	Staged (84 Row)	0.8	4.9	124	0.16
	10	67	Low	Staged (84C,83S,83N)	0.9	5.0	160	0.21
	11	52	Normal	Normal (None)	0.75	6.9	181	0.24
5/20	12	52	Low	Staged (84S,84N)	1.0	4.7	94	0.13
	16	50	Low	Staged (83S,83N)	0.9	4.6	124	0.16
5/24	14	22	Low	Staged (84S,84N)	0.8	12.9	158	0.21
	13	22	Normal	Normal (None)	0.75	12.1	191	0.25
	17	83	Low	Staged (83 Row)	0.7	4.4	132	0.18
	18	82	Low	Staged (84C,83S,83N)	0.7	4.5	124	0.16
	19	82	Low	Staged (83S,83N,82C)	0.7	4.7	142	0.19
	20	81	Low	Staged (83C,82S,82N)	0.65	4.4	123	0.16
5/26	21	47	Normal	Normal (None)	0.65	7.1	197	0.26
	22	31	Low	Staged (83 Row)	0.60	9.4	157	0.21
	23	29.5	Low	Staged (83S,83N,82C)	0.60	9.5	162	0.22
	24	22	Low	Staged (83S,83N,82C)	0.60	10.7	172	0.23
	25	23	Low	Staged (83 Row)	0.60	10.0	162	0.22
	26	23	Normal	Normal (None)	0.60	10.2	155	0.21

TABLE 6-28

EXPERIMENTAL DESIGN AND AVERAGE EMISSION MEASUREMENTS

Atlantic City Electric

(Deepwater Station, Boiler No. 8)

Oil Firing

	Full Load L_1 - 82 MW			Intermediate Load L_2 - 68 MW		Inter. Load L_3 - 52 MW		Inter. Load L_4 - 47 MW	Inter. Load L_5 - 30 MW	Low Load L_6 - 22 MW	
	A_1	A_{1-A}	A_2	A_1	A_2	A_1	A_2	A_1	A_2	A_1	A_2
S_1 Normal Firing Pattern I	① 4.5% O_2 246 PPM NO_x	(1A) 4.1% O_2 208 PPM NO_x	② 2.3% O_2 188 PPM NO_x	⑦ 5.5% O_2 204 PPM NO_x	⑧ 2.6% O_2 172 PPM NO_x	⑪ 6.9% O_2 181 PPM NO_x		㉑ * 7.1% O_2 197 PPM NO_x		⑬ 12.1% O_2 191 PPM NO_x ㉖ 10.2% O_2 155 PPM NO_x	
S_2 Staged Firing Pattern II			④ 5.2% O_2 136 PPM NO_x		⑨ 4.9% O_2 124 PPM NO_x		⑫ 4.7% O_2 94 PPM NO_x		㉒ * 9.4% O_2 157 PPM NO_x		⑭ 12.9% O_2 158 PPM NO_x
S_3 Staged Firing Pattern III			⑰ 4.4% O_2 132 PPM NO_x		⑩ 5.0% O_2 160 PPM NO_x		⑯ 4.64% O_2 124 PPM NO_x		㉓ * 9.5% O_2 162 PPM NO_x		㉔ * 10.7% O_2 172 PPM NO_x
S_4 Staged Firing Pattern IV	(5A) 5.3% O_2 192 PPM NO_x		(6A) 4.4% O_2 165 PPM NO_x								㉕ * 10% O_2 162 PPM NO_x
S_5 Staged Firing Pattern			⑱ 4.5% O_2 124 PPM NO_x								
S_6 Staged Firing Pattern			⑲ 4.7% O_2 142 PPM NO_x								
S_7 Staged Firing Pattern			⑳ 4.4% O_2 123 PPM NO_x								

* Small Oil Guns in Operating Burners

NOTE: Figures in boxes gives test run number, average % Oxygen and PPM NO_x (3% O_2, Dry Basis)

TABLE 6-29

FIRING PATTERNS USED DURING NO_x TESTING

Atlantic City Electric

(Deepwater Station, Boiler No. 8)

Oil Firing

Full Load 82 MW								Intermediate Load 68 MW			Intermediate Load 52 MW		
S_1	S_1	S_2	S_3	S_4	S_5	S_6	S_7	S_1	S_2	S_3	S_1	S_2	S_3
Run 1 & 2	Run 1A	Run 4	Run 17	Run 5A, 6A	Run 18	Run 19	Run 20	Run 7 & 8	Run 9	Run 10	Run 11	Run 12	Run 16
000 000 000 ●00	000 000 000 0●0	AAA 000 000 000	000 AAA 000 000	AOA 000 OAO 000	OAO AOA 000 000	000 AOA OAO 000	000 OAO AOA 000	000 000 000 ●0●	AAA 000 000 000	OAO AOA 000 000	000 000 0●0 ●●●	AOA 000 000 ●0●	000 AOA 000 ●0●

Burner Arrangement

	South	Center	North
84 Row	0	0	0
83 Row	0	0	0
82 Row	0	0	0
81 Row	0	0	0

Burner Nomenclature

0 - Oil Firing

A - Air Only

● - No Oil or Air

Inter. Load 47 MW	Int. Load 30 MW		Low Load 22 MW				
S_1	S_2	S_3	S_1	S_1	S_2	S_3	S_4
Run 21*	Run 22*	Run 23*	Run 13	Run 26*	Run 14	Run 24*	Run 25*
000 000 000 000	000 AAA 000 000	000 AOA OAO 000	000 0●0 ●●● ●●●	000 000 000 000	AOA 000 ●●● ●●●	000 AOA OAO 000	000 AAA 000 000

* Small Oil Guns in Operating Burners.

Baseline operation at full load (test run No. 1) conducted with all burners operating normally, except burner 81 south off, produced average flue gas NO_x concentrations of 246 ppm (3% O_2, dry basis) at 4.5 % O_2 in the flue gas. This is the only measurement recorded which exceeds the EPA-recommended emission standard of about 225 ppm for oil fired boilers. Reducing the excess air level to that corresponding to 2.3 % O_2 in the flue gas resulted in an average level of 188 ppm NO_x (3% O_2, dry basis), or a decrease of 23.5% from baseline conditions. Other staging patterns (tests 4, 5A, 6A, 17, 18, 19 and 20) achieved further reductions in NO_x emissions to as low as 123 ppm NO_x (50% reduction), but operating conditions were sometimes marginal. As indicated by the results in the attached tables, it is possible to operate at significantly reduced NO_x emission levels at all loads. However, these reductions were achieved at the expense of reduced superheat and reheat temperatures. Superheat temperatures were as much as 35°F low and 55°F on reheat during some tests at full load. At lower loads decreases as much as 140°F in superheat and 185°F in reheat resulted. Superheat and reheat surface would have to be added if the unit were to be operated full time at low NO_x emission conditions.

Carbon monoxide emission levels were generally lower than 100 ppm (well within the arbitrary limitation of 200 ppm criteria) but occasional wisps of gray stack emissions were observed during some tests, which may not be entirely acceptable. Smoke indicator readings during some of the "low NO_x" tests were slightly higher than normal but by no means exorbitant. If low NO_x emission firing conditions were to be employed full time, a thorough investigation of combustion conditions would be warranted since bad or worn sprayer plates on individual (single) burners could account for these undesirable visible emissions.

With some firing configurations, fans were operated at or near their maximum output. Fortunately, this did not occur at optimum NO_x reduction conditions but fan capacity limitations under some conditions of "low NO_x" operation might be a problem.

Baseline operation at the intermediate load of 68 MW (test No. 7) with all burners operating in the normal manner, and wing burners 81S and 81N off, produced average flue gas concentrations of 204 ppm NO_x (3% O_2, dry basis) at 5.5 % O_2 in the flue gas. Reducing the excess air to a level of 2.6 % O_2 in flue gas, reduced NO_x emissions to an average of 172 ppm, i.e., a reduction of about 16%. Other staging patterns (tests No. 9 and 10) made further reductions in NO_x emissions to a low of 124 ppm; a 40% reduction.

At 52 MW, baseline NO_x emission at 6.9 5 O_2 in the flue gas was 181 ppm (test No. 11). This was reduced to 124 ppm NO_x (31% reduction) by staging and reducing average excess air to a level of 4.6% O_2 in the flue gas.

At low load (22 MW) with large oil guns (test No. 13), the baseline NO_x emissions was 191 ppm NO_x at 12.1% O_2 in the flue gas. Replacing the large sprayer plates with smaller ones and firing all 12 burners produced a baseline NO_x emission (test No. 26) of 155 ppm at the 10.2% oxygen level. Applying staged firing techniques (test No. 14), reduced the baseline NO_x emission of 191 ppm down to 158 ppm, but, interestingly enough, staging patterns in comparable tests (tests No. 24 and 25 with small atomizers) produced higher emissions (172 and 162 ppm) than the 155 ppm baseline NO_x emission (test No. 26). Evidently, with the high excess air levels employed during these tests, the air/fuel ratio in the operating burners was too high for staging to be effective for NO_x emission control.

Table 6-30 contains average flue gas component emission measurements and flue gas temperatures. Percent O_2, percent CO_2, ppm NO_x, ppm CO are listed. The ppm data have been corrected to a 3% O_2, dry basis.

To sum up, baseline NO_x emissions on Boiler No. 8 of 246 ppm are slightly higher than the new source standard of about 225 ppm for oil fired boilers. Baseline emissions at other loads are normally below 200 ppm NO_x (3% O_2, dry basis). Staged firing was effective at all loads in reducing NO_x emission levels, except in two cases at low load, with high levels of excess air. The NO_x emission levels obtained with staged firing are all well below the EPA standard for new oil fired boilers. Because of fan and steam temperature control limitations, however, the NO_x emission reductions obtained were not always made at acceptable operating conditions. Both superheat and reheat steam temperatures during "low NO_x" emission conditions were low at all loads which seriously effect overall plant efficiency. Full time "low NO_x" operation would require the addition of superheat and reheat surface to overcome this undesirable deficiency. Also, under some conditions, visible grayish wisps were emitted from the stack, which could be attributed to damaged or worn sprayer plates on individual (single) burners. Long term operation at "low NO_x" conditions, therefore, should be preceded by a thorough revamping of the combustion system (including controls) to eliminate these undesirable visible emissions.

6.2.1.4 Deepwater, Boiler No. 9

Boiler No. 9 at Deepwater Station is a Combustion Engineering designed front wall fired, single furnace boiler, with a maximum continuous rating of 550,000 pounds of steam per hour. It was installed in 1957 to fire pulverized coal and has been recently converted to oil firing. The furnace width is 24 feet 3 inches and the furnace volume is 33,000 cubic feet with a heating surface of 8,625 square feet. Main steam operating pressure is 1325 pounds per square inch at a temperature of 765°F. There are six mechanical atomizing burners arranged in three rows of two burners each.

Table 6-31 lists operating and emissions data for the seven test runs conducted on this boiler. Operating variables were excess air level (normal and low) and burner firing patterns (normal firing plus three staged firing patterns). Gross load was maintained at about full rated capacity (20.8 to 22.8 MW). Low excess air was defined as the minimum excess air that produced only a slight visible plume with periodic wisps of gray smoke.

TABLE 6-30

FLUE GAS EMISSION MEASUREMENTS AND TEMPERATURES

Atlantic City Electric

(Deepwater Station, Boiler No. 8)

Oil Firing

TEST	GROSS	AVERAGE FLUE GAS MEASUREMENTS				
		O_2	CO_2	NO_x	CO	TEMP.
RUN N 1	LOAD (M 6)	%	%	PPM (3% O_2)	PPM (3% O_2)	°F
1	83	4.5	11.6	246	49	620
2	81	2.3	13.0	188	104	579
1A	82.5	4.1	11.5	208	56	615
4	81	5.2	10.5	136	83	608
6A	82	4.4	11.9	165	74	608
5A	83	5.3	11.3	192	74	615
7	68	5.5	10.6	204	62	607
8	66	2.6	12.4	172	65	547
9	66	4.9	11.2	124	59	570
10	67	5.0	11.3	160	60	607
11	52	6.9	9.6	181	64	593
12	52	4.7	11.2	94	64	517
16	50	4.6	11.0	124	64	521
14	22	12.9	4.8	158	104	495
13	22	12.1	5.5	191	80	522
17	83	4.4	11.6	132	78	609
18	82	4.5	11.9	124	84	590
19	82	4.7	11.6	142	70	600
20	81	4.4	11.8	123	64	595
21	47	7.1	9.4	197	63	560
22	31	9.4	7.5	157	72	520
23	29.5	9.5	7.1	162	70	505
24	22	10.7	6.5	172	66	498
25	23	10.0	6.5	162	64	490
26	23	10.2	6.7	155	66	495

TABLE 6-31

SUMMARY OF OPERATING AND EMISSION DATA

Atlantic City Electric

(Deepwater Station, Boiler No. 8)

Oil Firing

Boiler Operating Conditions				Flue Gas Measurements (1)		
Test Run No.	Gross Load (MW)	Excess Air Level	Firing Pattern (Burners on Air only) (2)	$\%O_2$	PPM NO_X ($3\%O_2$, Dry)	POUNDS NO_X PER 10^6 BTU
1	22.8	Nor	Nor.-(None)	1.8	286	0.38
2	22.8	Low	Nor.-(None)	1.0	253	0.34
3	21.7	Nor.	Staged-(1,4)-I	3.8	122	0.16
4	21.4	Low	Staged-(1,4)-I	2.6	101	0.13
5	20.8	Low	Staged-(1,5)-II	4.2	150	0.20
6	20.8	Nor.	Staged-(1,5)-II	4.8	152	0.20
7	21.9	Low	Staged-(2,5)-III	2.6	123	0.16

(1) Flue gas measurements made on gas smaples from 12 individual sampling tubes. Measurements shown are averages of 2 analyses from each of three sampling tubes (short, medium and long) per probe.

(2) Burner configuration

Top ① ④
Middle ② ⑤
Bottom ③ ⑥

Average ppm NO_x measurements (3% O_2, dry basis), pounds NO_x per 10^6 Btu and average % O_2 measurements are shown for each test run. Each of the four probes contained short, medium and long gas sampling tubes that were positioned to provide samples from the centers of twelve equal duct areas located between the economizer and air preheaters. Flue gas composition was uniform across the duct except for the staggered, staged-firing pattern II, as discussed below.

Table 6-32 indicates the experimental design of operating variables with average flue gas measurements of % oxygen and ppm NO_x (3% O_2, dry basis) shown for each run. A simplified furnace burner diagram is shown at the bottom of Table 6-32 to aid in visualizing the firing configurations used in the three different staged firing patterns. Figure 6-27 is a plot of ppm NO_x emission vs % oxygen in the flue gas for the four firing patterns investigated.

Baseline operations (test run No. 1) conducted with all six burners firing oil, produced average flue gas concentrations of 286 ppm NO_x (3% O_2, dry basis) or 0.38 pounds NO_x per 10^6 Btu heat input at 1.8% oxygen. Reducing the excess air level to that corresponding to 1.0% oxygen in the flue gas, resulted in an average level of 253 ppm NO_x (3% O_2, dry basis) or a decrease of 12% from baseline conditions. Staged firing pattern I (top row of burners on air only) operation resulted, as expected, in significant reductions in NO_x emission levels; 122 ppm at 3.8% oxygen and 101 ppm at 2.6% O_2. It should be noted that only about 80% of the air required for complete combustion of the fuel oil entered the active burners in run No. 3, and only about 75% of stoichiometrically required air entered the active burners in run No. 4.

Staged firing pattern II (Burners 1 and 5 on air only) operation did not produce as much NO_x emission reduction as staged firing pattern I, as shown by test runs 5 and 6, compared to runs 3 and 4. Staged firing pattern II produced an air-fuel imbalance with the left half of the furnace having a higher excess air level than the right half of the furnace. This resulted in raising the minimum excess air level of 2.5% O_2 in the flue gas achieved using staged firing pattern I, to 4.2% O_2 when using staged pattern II.

Run No. 7 made with low excess air and staged firing pattern III was conducted in an attempt to achieve low NO_x emissions with increased superheat temperatures. The NO_x level of 123 ppm obtained in run No. 7 was not as low as staged pattern I operation, but superheat temperature increased by about 5°F (760°F vs 755°F as measured at the turbine throttle, point 12).

Table 6-33 lists average flue gas component measurements and temperatures for each of the seven test runs completed--Deepwater Station Boiler No. 9. Percent O_2, percent CO_2, ppm NO_x, ppm CO and °F temperatures are shown.

FIGURE 6-27

PPM NO_x VS % O_2 MEASURED IN FLUE GAS

Atlantic City Electric

(B. L. England, Boiler No. 9)

Oil Firing

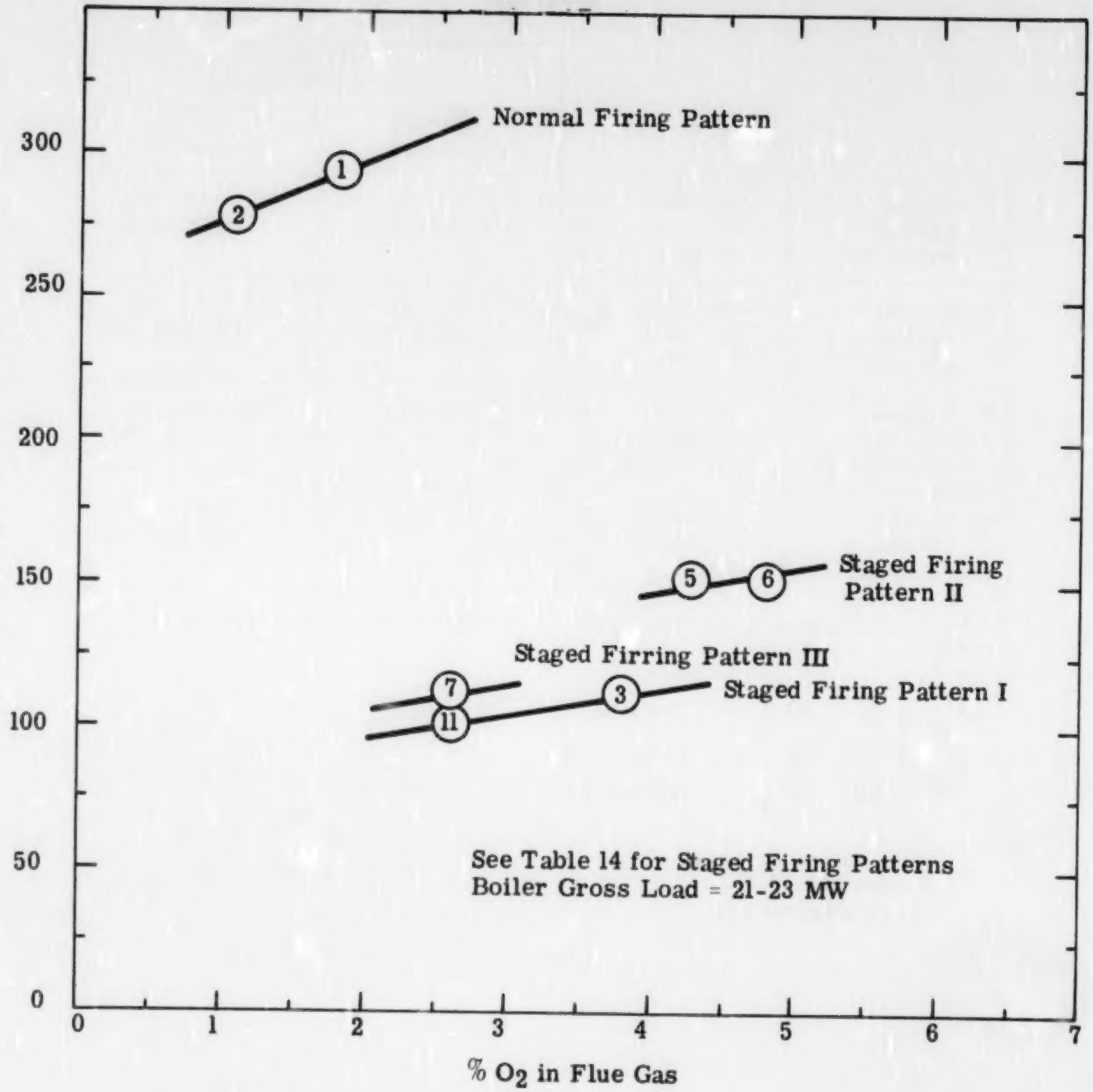


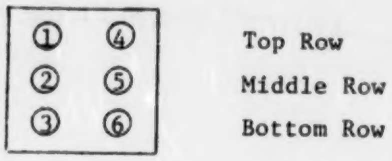
TABLE 6-32

EXPERIMENTAL DESIGN AND AVERAGE EMISSION MEASUREMENTS

Atlantic City Electric
(Deepwater Station, Boiler No. 9)
Oil Firing

			Full Load (21 - 23 MW Gross)	
			A_1-Normal Excess Air	A_2-Low Excess Air
S_1-Normal Firing Pattern:	Oil in All Burners	00 00 00	(1) 1.8% O_2 * 286 ppm NO_x	(2) 1.0% O_2 253 ppm NO_x
S_2-Staged Firing Pattern-I:	Air Only In Top Burners	AA 00 00	(3) 3.8% O_2 122 ppm NO_x	(4) 2.6% O_2 101 ppm NO_x
S_3-Staged Firing Pattern-II:	Air Only in Burners No. 1 & 5	AO OA 00	(6) 4.8% O_2 152 ppm NO_x	(5) 4.2% O_2 150 ppm NO_x
S_4-Staged Firing Pattern-III:	Air Only in Middle Burners	00 AA 00		(7) 2.6% O_2 123 ppm NO_x

* Each cell gives test run number, average % oxygen and ppm NO_x (3% O_2, dry basis).



Furnace Front:
Burner
Configuration

TABLE 6-33

FLUE GAS EMISSION MEASUREMENTS AND TEMPERATURES

Atlantic City Electric

(Deepwater Station, Boiler No. 9)

Oil Firing

TEST RUN NO.	GROSS LOAD (MW)	FLUE GAS MEASUREMENTS					
		O_2 %	CO_2 %	NO_x PPM ($3\%O_2$)	CO PPM ($3\%O_2$)	HC PPM ($3\%O_2$)	Temp. °F
1	22.8	1.8	13.5	286	44	--	739
2	22.8	1.0	14.0	253	97	--	717
3	21.7	3.8	11.5	122	45	--	734
4	21.4	2.6	12.6	101	64	--	717
5	20.8	4.2	11.4	150	60	--	717
6	20.8	4.8	10.9	152	48	--	726
7	21.0	2.6	12.4	123	53	--	703

To sum up, this boiler has baseline NO_x emissions of 286 ppm. Low excess air plus staged firing operation resulted in a significant lowering of NO_x emissions, as shown in Figure 6-27. Three different staged firing patterns were effective with staged pattern I (top burners on air only) producing the lowest average NO_x emission level of 101 ppm (3% O_2, dry basis). The NO_x emission levels reached with staged firing are all well below the EPA recommended standards for oil fired boilers. It was possible to reduce NO_x emissions to these levels for this boiler without any adverse effects such as significantly increased smoke and unburned combustible emissions, and reduced boiler operability.

6.2.2 Cyclone Fired Boilers

6.2.2.1 B. L. England, Boiler No. 1

Boiler No. 1 at the B.L. England Station is a Babcock & Wilcox Company, cyclone fired pressurized boiler with a maximum continuous rating of 930,000 lb. steam/hour. It was installed in 1957, and has recently been converted to crude oil firing. Design pressure is 1815 psi, and electricity output is 136 MW gross (127 MW net) at steam and reheat temperatures of 1000/1000°F. The boiler is fired by single, mechanical atomizing oil burners in each of the three cyclones, which are arranged with two of them on one level, with the third one elevated between them in a triangular fashion on the front wall of the furnace.

Table 6-34 lists operating and emissions data for the seven test runs conducted on this boiler. Operating variables were excess air (normal, intermediate, and low) and load (full, intermediate, and low). Gross load was maintained at about full rated capacity on crude oil firing (132-133 MW) at normal, intermediate, and low excess air firing conditions. Tests were also made at three similar excess air levels at intermediate loads of 103-105 MW. Emission data were also obtained at normal excess air conditions at "minimum" load (62 MW). Low excess air at full load was defined as 1.1% O_2 on the control board oxygen meter (0.5% avg. O_2 measured by the Exxon van). At these levels, smoke density on ACE's smoke meter was normal (30), and no visible emissions were apparent from the stack. Carbon monoxide emissions as measured by the Esso van, however, were excessive and, therefore, operation at such low level of excess air would not be recommended. Low excess air for the intermediate load of about 103 gross MW's was defined as the minimum excess air that produced only a slightly visible stack plume, no appreciable increase in smoke density indication, and reasonable (about 200 ppm max.) CO emissions. Average ppm NO_x measurements (3% O_2, dry basis) pounds $NO_x/10^6$ Btu and average % O_2 measurements are shown for each test run. Each of the four probes contained short, medium, and long gas sampling tubes which were positioned to provide samples from the centers of twelve equal duct areas located between the economizer and the air preheaters.

TABLE 6-34

SUMMARY OF OPERATING AND EMISSION DATA

Atlantic City Electric

(B. L. England, Boiler No. 1)

Oil Firing

Boiler Operating Conditions				Average Flue Gas Measurements(1)			
Test Run No.	Gross Load MW	Excess Air Level	Firing Pattern	Smoke Density	$\%O_2$	PPM NO_X ($3\%O_2$, Dry)	POUNDS NO_X PER 10^6 BTU
1	133	Normal	All Cyc. On	30	1.5	441	0.59
2	133	Inter.	All Cyc. On	30	1.1	396	0.53
3	132	Low(2)	All Cyc. On	30	0.5	313	0.42
4	62	Normal	Middle Cyc. Off	24	4.2	261	0.35
5	105	Normal	All Cyc. On	26	2.7	404	0.54
6	105	Inter.	All Cyc. On	26	2.4	364	0.48
7	103	Low	All Cyc. On	25	1.0	241	0.32

(1) Flue gas measurements made on composite gas samples from 3 individual sampling tubes. Measurements shown are averages of 3 analyses from three sampling tubes (short, medium, and long) for each of 4 probes.

(2) Excessively high CO emissions at this condition.

Table 6-35 indicates the experimental design of operating variables with average flue gas measurements of % oxygen and ppm NO_x (3% O_2, dry basis) shown for each run. Normal firing patterns with all three cyclones firing were employed for all, except low load operation. In the latter case, the middle or upper cyclone was taken out of service. Figure 6-28 is a plot of ppm NO_x emission vs. % oxygen in the flue gas for the three loads tested.

Baseline operations (test run No. 1) conducted with all three cyclones operated normally, produced average flue gas concentrations of 441 ppm NO_x (3% O_2, dry basis) at 1.5% oxygen. Reducing the excess air level to 1.1 and 0.5% oxygen in the flue gas resulted in a reduction in average emission levels at this load to 396 and 313 ppm NO_x (3% O_2, dry basis), respectively. Baseline operation at 105 MW output produced 404 ppm NO_x (3% O_2, dry basis) at the level of 2.7% O_2 in the flue gas. Reducing excess air to 2.4 and 1.0% O_2 in the flue gas reduced NO_x emissions to 364 and 241 ppm, respectively, at the intermediate load. At the minimum load of 62 MW, a baseline emission level of 261 ppm NO_x (3% O_2, dry basis) was measured at 4.2% oxygen. This level is about the same as the emissions at the intermediate load level of 105 MW at low excess air conditions, indicating the particularly significant contribution of fuel nitrogen oxidation to NO_x emission at intermediate to low load levels, i.e., at lowered combustion intensity conditions.

Decreasing excess air levels at both full and intermediate loads had a substantial effect on reducing NO_x emission levels. With cyclone operation, at least at present, staged firing patterns which might effect further reductions are not possible.

Table 6-36 lists average flue gas component measurements and temperatures for each test run. Percent O_2, percent CO_2, ppm NO_x, ppm CO and temperatures are shown. The ppm data have been corrected to a 3% O_2, dry basis.

To sum up, this boiler has baseline NO_x emissions of 441 ppm which are higher than the original recommended new source emission standards of about 225 ppm for oil fired boilers. Low excess air operation at full and intermediate loads resulted in significant lowering of NO_x emissions as shown in Figure 6-28. However, decreases in load and reductions in excess air levels could not reduce emissions below the recommended standards for new boilers which are subject to reassessment at present by EPA).

6.2.2.2 B. L. England, Boiler No. 2

Boiler No. 2 at ACE's B.L. England Station is a Babcock & Wilcox Company, cyclone fired, pressurized boiler with a maximum continuous rating of 1,250,000 lb. of steam per hour. The unit was installed in 1964, and has recently been converted to crude oil firing. Electricity output is 168 MW gross (160 MW net) at design pressure of 1815 psi, with 1000/1000°F superheat and reheat temperatures. Each of the four cyclones are fired by a single mechanical pressure, atomizing oil gun. The four cyclones are arranged in a square pattern in the front wall of the boiler, two at each elevation as detailed in Table 6-38.

TABLE 6-35

EXPERIMENTAL DESIGN AND AVERAGE EMISSION MEASUREMENTS

Atlantic City Electric

(B. L. England, Boiler No. 1)

Oil Firing

	Full Load 133 MW			Intermediate Load 105 MW			Low Load 62 MW
	A_1 Normal Air	A_2 Inter Air	A_3 Low Air	A_1 Normal Air	A_2 Inter Air	A_3 Low Air	A_1 Normal Air
S_1 Normal Firing Pattern Cyclone Arrangement	① 1.5% O_2 441 PPM NO_x	(2) 1.1% O_2 396 PPM NO_x	③ 0.5% O_2 313 PPM NO_x	⑤ 2.7% O_2 404 PPM NO_x	⑥ 2.4% O_2 364 PPM NO_x	1.0% O_2 241 PPM NO_x	④ *4.2% O_2 261 PPM NO_x

* B Cyclone Off

Figure 6-28

PPM NO_x VS O_2 MEASURED IN FLUE GAS

Atlantic City Electric

(B. L. England, Boiler No. 1)

Oil Firing

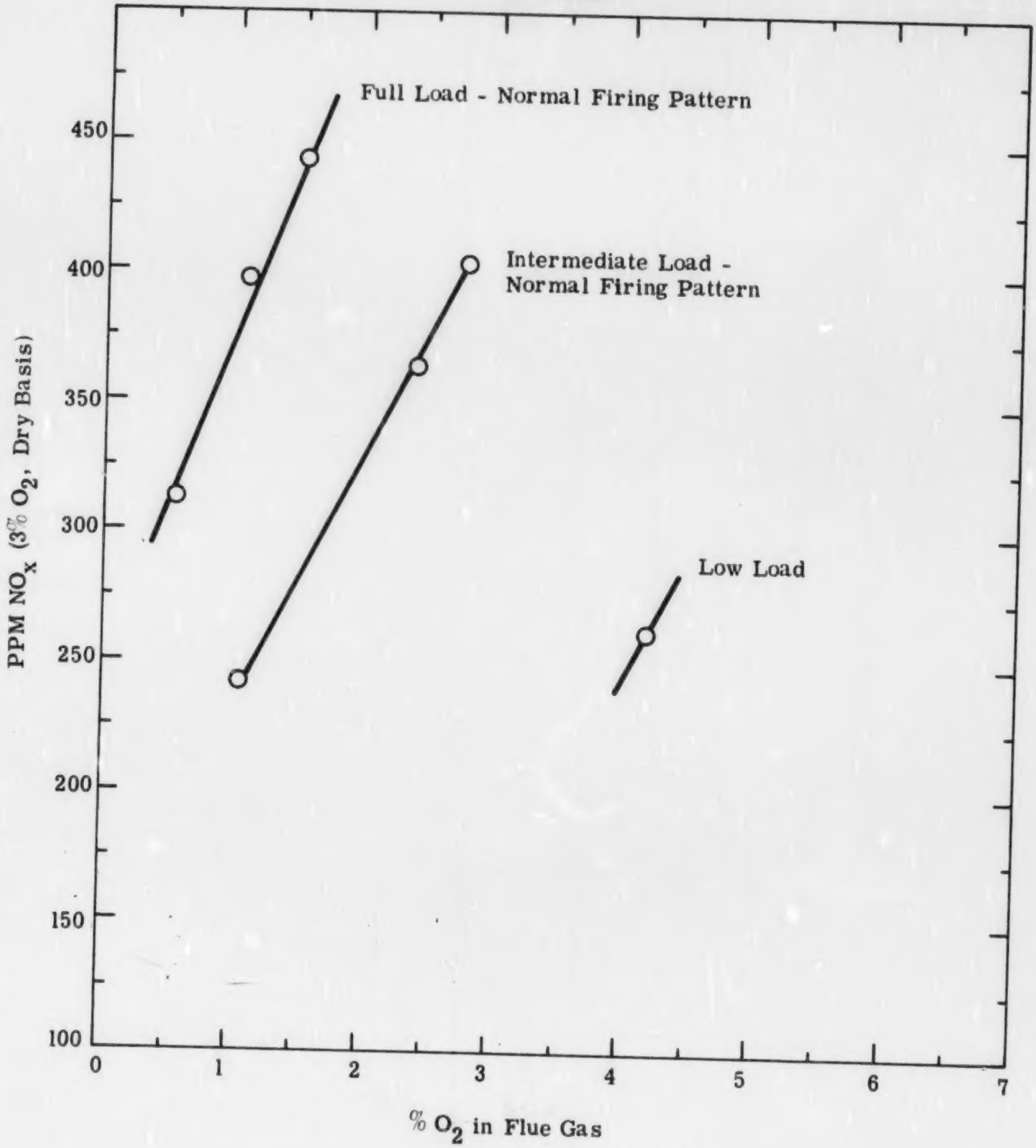


TABLE 6-36

FLUE GAS MEASUREMENTS AND TEMPERATURES

Atlantic City Electric

(B. L. England, Boiler No. 1)

Oil Firing

TEST RUN NO.	GROSS LOAD MW	AVERAGE FLUE GAS MEASUREMENTS				
		O_2 %	CO_2 %	NO_x ppm (3% O_2)	CO ppm (3% O_2)	TEMP. °F
1	133	1.5	13.1	441	57	762
2	133	1.1	13.1	396	74	760
3	132	0.5	13.2	313	1523	748
4	62	4.2	11.9	261	54	626
5	105	2.7	12.7	404	59	727
6	105	2.4	12.9	364	53	715
7	103	1.0	13.8	241	68	697

Table 6-37 lists operating and emission data for the two test runs conducted on this boiler. As agreed upon with ACE, the only operating variable during these tests was excess air. Low excess air was defined as the minimum excess air that produced only a slight visible plume with periodic wisps of gray smoke, no appreciable increase in smoke meter indications, and reasonable increases in CO emission levels (i.e., <200 ppm). Average ppm NO_x measurements (3% O_2, dry basis) pounds $NO_x/10^6$ Btu and average % O_2 measurements are shown in Table 6-37 for each test run. Each of the four probes contained short, medium, and long gas sampling tubes that were positioned to provide samples from the centers of equal areas across the width of the duct at each probe. Gas sampling probes were located between the economizers and the air preheater. Flue gas composition, except for probe No. 1 located on the left hand side of the boiler, was fairly uniform. Unbalanced gas flow was experienced on the unit with the major part of the flow concentrated on the left hand side at probe No. 1.

Table 6-38 shows the operating variables, excess air, with average flue gas measurements of % oxygen and ppm NO_x (3% O_2, dry basis) for each run. The cyclone configuration is shown at the bottom of Table 6-38.

Baseline operations (test run No. 1) conducted at full load with all four cyclones firing crude oil, produced average flue gas NO_x concentrations of 361 ppm (3% O_2, dry basis) at 2.2% oxygen. Reducing the excess air level to that corresponding to 1.6% oxygen in the flue gas resulted in an average level of 303 ppm NO_x (3% O_2, dry basis), or a decrease of 16% from baseline conditions.

Table 6-39 lists average flue gas component measurements and temperatures for each test run. Percent O_2, percent CO_2, ppm NO_x, ppm CO and temperatures are shown. The ppm data are listed on a 3% O_2, dry basis.

To sum up, this boiler has baseline NO_x emissions of 361 ppm NO_x which are higher than the original EPA recommended standards of about 225 ppm for new oil fired boilers. Low excess air operation resulted in a 16% reduction in NO_x emissions, but could not reduce them below recommended standard levels. This reduction in NO_x emissions was achieved without any adverse effects, such as significantly increased smoke, unburned combustible emissions, or reduced operability.

TABLE 6-37

SUMMARY OF OPERATING AND EMISSION DATA

Atlantic City Electric

(B. L. England, Boiler No. 2)

Oil Firing

Boiler Operating Conditions				Flue Gas Measurements(1)			
Test No.	Gross Load MW	Excess Air Level	Firing Pattern	Smoke Meter	$\%O_2$	PPM NO_X ($3\%O_2$, Dry)	POUNDS NO_X PER 10^6 BTU
1(2)	167	Normal	All Burners On	24	2.2	361	0.48
2(2)	167	Low	"	24	1.6	303	0.42

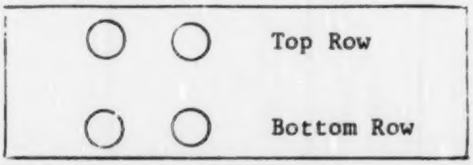
(1) Flue gas measurements are averages of three composite flue gas samples taken from each of 4 probes.

TABLE 6-38

EXPERIMENTAL DESIGN AND AVERAGE EMISSION MEASUREMENTS

Atlantic City Electric
(B. L. England, Boiler No. 2)
Oil Firing

	Full Load 167 MV	
	A_1 Normal Excess Air	A_2 Low Excess Air
S_1 Normal Firing Pattern	2.2% O_2 361 PPM NO_x	1.6% O_2 303 PPM NO_x



Cyclone Configuration

NOTE: Each run number gives average % oxygen and ppm NO_x (3% O_2 dry basis).

TABLE 6-39

FLUE GAS EMISSION MEASUREMENTS AND TEMPERATURES

Atlantic City Electric

(B. L. England, Boiler No. 2)

Oil Firing

DATE	TEST RUN NO.	GROSS LOAD MW	FLUE GAS MEASUREMENTS (1)				TEMPERATURES
			O_2	CO_2	NO_x	CO	
			%	%	ppm @ 3% O_2	ppm @ 3% O_2	°F
5/8/73							
	1	167	2.2	13.5	361	85	701
	2	167	1.6	13.5	303	231	698

(1) Average of three 2-minute gas composites from each of four probes.

7. RECOMMENDATIONS FOR FURTHER FIELD TESTING

As discussed in Section 2, major problem areas and potential limitations of combustion control techniques for NO_x reduction that remain for coal fired boilers have been well defined. Primary emphasis in further field test programs should be placed on the longer period, difficult operating problems of coal fired boilers under "low NO_x" combustion control as detailed below. In addition, gas turbines and stationary internal combustion engines should be field tested because of their expanding number and importance in electric power generation. This factor is directly related to the contribution of equipment categories to the overall NO_x emission problem for stationary sources.

7.1 Utility Boiler Testing

Table 7-1 summarizes the number of boilers by fuel and type of firing recommended for future field testing based on the results of the present work and prior Esso field studies (4-6).

TABLE 7-1

NUMBER AND TYPE OF UTILITY BOILERS TO BE TESTED IN FUTURE FIELD TEST PROGRAMS

	Fuel Fired:			
Type of Firing	Coal	Mixed Fuels	Waste Fuel	Expected Total
Wall (FW + HO)	3	1	1	5
Tangential	3	1	1	5
Cyclone	1			1
Turbo Furnace	1	–	–	1
Expected Total	8	2	2	12

Major emphasis should be placed on coal fired boilers. However, mixed fuels (combinations of coal, gas and oil) and waste-fired fuels should also be tested. Wall fired (front wall and horizontally opposed) and tangentially fired boilers should be given about equal emphasis. One or two cyclone furnace boilers and a turbo furnace boiler should be tested if sufficiently flexible boilers can be located and arrangements with boiler operators can be made.

The coal types to be included in future testing should encompass Western low-sulfur bituminous and sub-bituminous, lignite, Midwestern bituminous and Eastern bituminous and sub-bituminous coals. Because of their increasing performance as national energy resources, priority should be given to Western coals and lignite. Simultaneously fired fuels should include combinations of coal and oil, coal and gas, and oil and gas. The waste fuel fired boiler could be either waste alone, or a combination of waste and fossil fuel fired.

The basis for selecting specific boilers for testing within each of the four types of firing groups includes an evaluation of all pertinent operating factors in addition to being representative of current design practices of major boiler manufacturers.

Operating flexibility is the prime selection criteria. Boilers designed to operate with "NO-ports" or "overfire" air-ports and/or flue gas recirculation into the windbox should be especially sought out for inclusion into future test programs. In addition, the operator's ability and willingness to fire with low excess air, to employ staged combustion, to utilize water injection, to control air and fuel to individual burners and to reduce loads are highly important. Obviously, the boilers selected must be in good repair and have the proper instrumentation and controls so that good data for fuel usage, combustion and steam-side analysis can be obtained. Also, the boiler operator's willingness to cooperate by providing proper sampling ports, assistance in obtaining fuel and ash samples, good supervision for the required safe changes in operation, research-mindedness and experience in NO_x control should be taken into account. The boiler selection process will be greatly assisted with the continued cooperation of boiler manufacturers and boiler operators experienced in our present and previous field study programs.

The cooperative planning effort of the current field test program provides a recommended framework for future test programs. Exxon Research developed a comprehensive list of selection criteria to assist EPA and boiler manufacturers in preparing a list of potential boiler candidates. Each boiler manufacturer submitted a list of suggested boilers to EPA for review and screening. After consideration of such factors as design variables, operating flexibility, fuel type, geographic location and logistics, a tenative list of boilers was selected by EPA and Exxon. Field meetings were then held at power stations to confirm the validity of the boilers selected and to obtain necessary boiler operating and design data.

Since it is desirable to test representative types of coal and mixed fuels that are fired in different geographic regions of the United States, it will be desirable to minimize travel time by utilizing the concept of cluster sampling. Consideration should be given to testing in fringe areas where different fuel types can be supplied to the same boilers.

The scope and order of work to be performed on each boiler can be described in terms of an expanded version of our current three stage program. First, a statistically designed program of short-period test runs should be conducted, incorporating all available combustion control variables, to determine the optimum and near optimum operating conditions for NO_x emission control under both full load and reduced load operation. Second, the boiler should be operated for 1 to 3 days under sustained low NO_x conditions, to validate optimum NO_x emission reduction conditions, and to assess potential boiler operability problems such as slagging and steam temperature control. Third, sustained 300-hour runs should be made under both baseline and "low NO_x" operation. During these periods, air-cooled carbon steel coupons will be exposed to combustion gases in the vicinity of furnace water tubes, to determine through corrosion tests whether operating the boiler under the reducing conditions associated with low excess air and staged firing results in increased fire-side water-tube corrosion rates. Particulate samples should also be obtained under both baseline and "low NO_x" operations to determine if increased amounts of unburned carbon on fly ash result; also to determine if fly ash loadings increase under "low NO_x" operations. The samples should be analyzed for trace constituents. Boiler operating data should be recorded in order to determine boiler efficiency, and operating observations should be recorded to assess operating problems, such as excessive furnace slagging or steam temperature problems.

Several additional work items should be included in the enlarged three stage testing program in future boiler tests.

- The 300-hour sustained runs on selected boilers should be extended to a six-month period. A representative sample of tube wall thickness measurements should be made under normal conditions and before and after the sustained run to compare with coupon corrosion measurements.

- Precipitator performance tests should be made during both baseline and "low NO_x" operations.

- Particle size distribution and conductivity tests should be made on fly ash samples,and flue gas SO_3 measurements obtained in conjunction with performance test so that cause-effect relationships may be established.

- Flue gas particulate measurements should be made both upstream and downstream of electrostatic precipitators, to assess the effect of combustion modifications on precipitator performance.

- The particulates collected should be analyzed for potentially hazardous trace constituents, such as Hg, Cd, Be and Cd. Special attention should be paid to the effects of combustion modifications on the potential segregation of such constituents into different particle size ranges.

- Furnace slagging observations should be quantified as far as practical and related to changes in fuel composition and boiler operation. Representative samples of raw coal, furnace slag, fly ash and bottom ash as well as flue gas should be taken during both sustained baseline and "low NO_x" operations. These samples should be analyzed so that changes in slag observations can be correlated with coal quality (heating value, % ash, ash composition, ash viscosity, ash softening point, ash melting point etc.) and other operating parameters affecting combustion. Mill performance (coal fineness), fuel distribution (burner to burner), air distribution (uniformity of secondary air register openings from burner to burner, or side to side variation due to plugged air heaters on unbalance in forced or induced draft fans), flame shape (coal spreader condition and setting, air register setting, coal nozzle setting, burner head distribution vane setting) burner line velocities, staged firing pattern, and excess air level are some of the operating variables that should be observed and recorded for rigorous regression analysis with slagging observations. This systematic approach is necessary for solving the slagging problems that had been identified, but were beyond the scope of the present and past field test program.

8. REFERENCES

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APPENDIX A

OPERATING AND GASEOUS EMISSION DATA SUMMARIES

This section of the report contains 12 tables summarizing the operating and gaseous emission data by test run for each of the 12 coal fired boilers tested.

Table	Boilers
1	Widows Creek No. 6
2	Dave Johnston No. 2
3	E. D. Edwards No. 2
4	Crist No. 6
5	Harllee Branch No. 3
6	Leland Olds No. 1
7	Four Corners No. 4
8	Barry No. 3
9	Naughton No. 3
10	Dave Johnston No. 4
11	Barry No. 4
12	Big Bend No. 2

Hydrocarbon and SO_2 measurements made in this study are not included in the tables of Appendix A for the following reasons. In all cases, the volatile hydrocarbon emission levels were negligible, in line with our previous experience in field testing coal-fired boilers (4-6). While SO_2 emissions were measured, it is felt that in general these results are not reliable because of instrument calibration problems. This will be corrected for future field testing studies so that the effect of combustion modifications on flue gas SO_3/SO_2 ratios can be determined.

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* The initial SO_2 concentration of fresh calibration gas cylinders has been found to decrease with time (presumably due to the adsorption of SO_2 on the walls of the gas cylinder). This problem will be eliminated in future studies by frequent re-checking of the certified calibration gases.

TABLE 1

SUMMARY OF OPERATING AND EMISSION DATA - WIDOWS CREEK BOILER NO. 6

(125 MW, Front Wall, Pulverized Coal Fired)

	Boiler Operating Conditions						Average Gaseous Emissions and Temperatures						
		Firing Pattern			Secondary	Exc. Air	NO_x		O_2	CO_2	CO	HC**	Temp.
			Burners										
Date and Run No.	Gross Load (MW)	Code	No. on Coal	On Air Only	Air Registers (% Open)	Level - % Stoic. Act. Bur.	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	%	%	PPM 3% O_2 Dry	PPM 3% O_2 Dry	°F
4/12/72													
1	125	S_1	16		60	Nor-117	577	0.77	3.2	15.4	329	-	699
2	125	S_1	16		60	Min-110	491	0.65	2.0	16.2	814	-	691
3	125	S_1	16		20	Nor-115	610	0.81	2.8	15.4	247	-	701
4	125	S_1	16		20	Min-109	505	0.67	1.9	16.2	523	-	691
4/17/72													
5	126	S_2	14	D_1D_4	60	Nor-108	558	0.74	4.0	14.1	359	-	716
6	119	S_2	14	D_1D_4	20	Min-96	372	0.49	2.0	16.0	1049	-	686
7	122	S_3	14	A_1A_4	20	Nor-110	532	0.71	4.5	13.9	491	-	707
8	120	S_3	14	A_1A_4	60	Min-100	368	0.49	2.7	15.0	833	-	692
4/18/72													
20A	115	S_8	12	$B_1B_2B_3B_4$	60	Min	371	0.49	2.2	16.4	899	-	672
9	125	S_3	14	A_1A_4	60	Nor-107	518	0.69	4.1	14.5	383	4	703
10	125	S_3	14	A_1A_4	20	Min-94	345	0.46	1.7	16.3	1027	3	681
11	125	S_2	14	D_1D_4	20	Nor-106	632	0.85	3.8	14.2	415	3	711
12	121	S_2	14	D_1D_4	60	Min-94	406	0.54	1.5	15.5	976	3	683
1A	125	S_1	16		60	Nor-118	669	0.89	3.3	14.4	394	2	700
4/19/72													
13	110	S_4	12	$A_1A_2A_3A_4$	60	Nor-94	460	0.61	4.5	14.3	773	1	678
14	110	S_5	12	$A_1A_4B_2B_3$	60	Min-86	342	0.45	2.6	15.2	594	-	672
15	112	S_6	12	$A_1A_4B_1B_4$	20	Nor-99	471	0.63	5.2	12.5	176	-	706
4/20/72													
18	110	S7	12	$A_1A_4D_1D_4$	20	Nor-94	418	0.56	4.3	14.6	1110*	-	694
16	110	S_7	12	$A_1A_4D_1D_4$	20	Min-86	329	0.44	2.9	15.4	3090*	-	685
19	110	S_6	12	$A_1A_4B_2B_3$	20	Min-88	301	0.40	3.1	14.9	3180*	-	688
17	112	S_5	12	$A_1A_2B_3B_4$	60	Nor-94	480	0.64	4.4	14.0	167	-	704
20	108	S_4	12	AAAA	60	Min-87	345	0.46	3.0	15.0	1920*	-	696
4/21/72													
1B	128	S_1	16		60	Nor-120	656	0.87	3.6	15.1	52	-	-
4/24/72													
21	80	S6	12	$A_1A_4B_1B_4$	60	Nor-105	550	0.73	6.1	12.3	40	-	684
23	83	S_7	12	$A_1A_4D_1D_4$	60	Min-92	438	0.58	3.9	13.8	292*	-	668
22	88	S_5	12	$A_1A_4B_2B_3$	20	Min-89	306	0.41	3.4	13.9	572*	-	672
24	89	S_4	12	$A_1A_2A_3A_4$	20	Nor-94	399	0.53	4.5	13.0	141*	-	681
4/25/72													
25	110	S_7	12	$A_1A_4D_1D_4$	60	Nor-94	495	0.66	4.5	14.0	210*	-	696
28	100	S_6	12	$A_1A_4B_1B_4$	60	Min-94	438	0.58	4.5	13.6	389*	-	682
27	103	S_5	12	$A_1A_4B_2B_3$	20	Nor-97	496	0.66	4.9	13.4	83	-	695
26	99	S_4	12	$A_1A_2A_3A_4$	20	Min-86	297	0.40	2.7	14.8	840*	-	668
4/26/72													
31	112	S_1	16		20	Nor-129	681	0.91	4.9	12.7	61	-	707
32	106	S_1	16		20	Min-115	464	0.62	2.8	14.6	407	-	680
29	110	S_1	16		60	Nor-129	629	0.84	4.8	14.1	52	-	702
30	106	S_1	16		60	Min-114	450	0.60	2.7	15.9	530	-	678
4/27/72													
$10A_1$	120	S_3	14	A_1A_4	20	Min-105	409	0.54	3.6	14.7	650	-	696
5/1/72													
$10/C_1$	120	S_3	14	A_1A_4	20	Min-102	343	0.46	3.0	14.8	867	-	690
5/2/72													
$10/C_3$	125	S_3	14	A_1A_4	20	Min-103	397	0.53	3.3	15.0	414*	-	698
5/3/72													
$10/C_5$	123	S_3	14	A_1A_4	20	Min-102	403	0.54	3.2	15.2	366	-	696
$26A_1$	97	S_4	12	$A_1A_2A_3A_4$	20	Min-86	299	0.40	2.8	15.1	748	-	680
5/4/72													
$26A_3$	103	S_4	12	$A_1A_2A_3A_4$	20	Min-85	290	0.39	2.5	15.9	867	-	685

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* High variation in CO measurements between probes.

** Hydrocarbons were measured on each test but values were negligible except where indicated.

TABLE 2

SUMMARY OF OPERATING AND EMISSION DATA - DAVE JOHNSTON, BOILER NO. 2

(105 MW, Front Wall Pulverized Coal Fired)

Date and Run No.	Boiler Operating Conditions					Average Gaseous Emissions				
				Excess Air		NO_x		O_2	CO_2	CO
	Gross Load MW	Firing Pattern: Mills Off	Secondary Air Register Settings on Off Mills	Target	% Stoic. To Act. Burners	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	%	%	PPM (3% O_2, Dry)
7/27/73										
3	101	12	Closed	Nor.	130	454	0.60	5.0	14.3	112
4	101	12	Closed	Low	125	409	0.54	4.3	14.6	731
7/30/73										
1	102	11,12	Closed	Nor.	125	450	0.60	4.3	15.3	28
6	102	11,12	11 Op., 12 Cl.	Low	94	362	0.48	3.3	16.4	112
5	102	11,12	Partly Open	Low	82	311	0.41	4.0	16.3	308
2	102	11,12	11 Cl., 12 Op.	Low	99	284	0.38	4.2	16.0	277
7/31/73										
8	103	11,12	11 Cl., 12 Op.	Nor.	102	347	0.46	4.6	14.4	370
10	103	11,12	Open	Nor.	85	358	0.48	4.6	14.8	96
7	101	11,12	Closed	Low	120	413	0.55	3.7	15.2	117
8/1/73										
12	106	12	Open	Low	102	314	0.42	4.1	15.1	918
14	102	10,12	10 Cl., 12 Op.	Low	102	270	0.36	4.7	14.5	1054
16	99	10,12	Open	Low	88	214	0.28	5.2	13.4	962
15	98	10,12	10 Op., 12 Cl.	Low	106	326	0.43	5.3	13.4	620
13	99	10,12	Closed	Nor.	132	438	0.58	5.2	13.4	420

NOTE: Hydrocarbons were measured on each test but values were negligible except where indicated.

TABLE 3

SUMMARY OF OPERATING AND EMISSION DATA - E. D. EDWARDS, BOILER NO. 2

(260 MW, Front Wall, Pulverized Coal Fired)

	Boiler Operating Conditions							Average Gaseous Measurements					
		Firing Pattern			Secondary	Excess Air		NO_x		O_2	CO_2	CO	Temp.
			Burners										
Date and Run No.	Gross Load (MW)	Code	No. On Coal	On Air Only	Air Registers (% Open)	Target	% Stoic. To Active Burners	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	%	%	PPM (3% O_2, Dry)	°F
6/11/63													
1	256	S_1	16	None	45-50	Nor.	117	670	0.89	3.2	14.8	69	644
2	251	S_1	16	None	45-50	Low	107	556	0.74	1.5	16.0	93	622
6/12/63													
5	255	S_2	14	1,4	45-50	Nor.	106	644	0.86	3.8	14.6	18	649
6	256	S_2	14	1,4	20	Low	94	359	0.48	1.6	16.2	172	642
3	254	S_1	16	None	20	Nor.	117	770	1.02	3.1	14.4	16	644
4	255	S_1	16	None	20	Low	109	692	0.92	1.8	15.4	29	637
6/13/63													
23	212	S_1	16	None	50	Nor.	124	668	0.89	4.2	14.1	17	620
24	204	S_1	16	None	50	Low	108	516	0.69	1.6	16.3	54	597
13	238	S_4	12	1,2,3,4	50	Nor.	97	535	0.71	4.9	13.2	23	647
18	238	S_4	12	1,2,3,4	50	Low	89	386	0.51	3.5	14.1	234*	633
8	250	S_3	14	2,3	50	Low	100	524	0.70	2.7	14.3	117	636
7	250	S_3	14	2,3	20	Nor.	108	401	0.53	4.0	13.3	28	640
6/14/63													
14	229	S_4	12	1,2,3,4	30	Low	94	310	0.41	4.4	13.3	215*	627
10	243	S_2	14	1,4	50	Low	96	474	0.63	2.0	16.6	200*	630
11	250	S_3	14	2,3	50	Nor.	106	609	0.81	3.8	14.4	19	647
12	249	S_3	14	2,3	30	Low	96	382	0.51	2.1	15.7	333	474
9	252	S_2	14	1,4	30	Nor.	107	625	0.83	3.9	14.4	22	633
6/15/63													
16	221	S_5	12	1,4,6,7	50	Low	86	336	0.45	2.8	15.0	257	613
20	221	S_5	12	1,4,6,7	30	Low	87	295	0.39	3.0	14.6	26	610
1A	250	S_1	16	None	50	Nor.	121	736	0.98	3.8	14.2	16	647

NOTE: Hydrocarbons were measured on each test but values were negligible except where indicated.

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* Average values increased due to high CO measurements with one of 4 probes.

TABLE 4

SUMMARY OF OPERATING AND EMISSION DATA - CRIST, BOILER NO. 6

(340 MW, Front Wall, Pulverized Coal Fired)

	Boiler Operating Conditions								Flue Gas Emission Measurements													
		Firing Pattern				Excess Air			Duct A							Duct B						
			Burners				% Stoic. Air To Active Burners		NO_x		O_2	CO_2	CO	HC	Temp.	NOx		O_2	CO_2	CO	HC**	Temp.
Date and Run No.	Gross Load (MW)	Code	No. on Coal	On Air Only	Secondary Air Registers (% Open)	Target	A	B	PPM (3% O_2)	Pounds/ 10^6 BTU	%	%	PPM (3% O_2)	PPM 3% O_2	°F	PPM 3% O_2	Pounds/ 10^6 BTU	%	%	PPM (3% O_2)	PPM (3% O_2)	°F
12/6/72					(Oper/Idle)	(1)																
3	315	S	14	1,4	70/70	N	98	104	724	0.96	2.3	--	38	-	653	631	0.84	3.4	--	42		685
2	318	S_2	14	1,4	70/0*	N	112	112	946	1.26	4.7	13.5	26	-	619	872	1.16	4.7	13.4	32	-	662
12/7/72																						
26	350	S_1	16	None	70/-	N	119	115	898	1.20	3.4	15.0	24	-	-	743	0.99	2.9	15.3	27	-	704
12/8/72																						
4	318	S_3	14	2,3	70/0*	N	94	108	516	0.69	1.4	15.9	44	-	648	546	0.73	4.0	13.6	36	-	671
5	320	S_3	14	2,3	70/70	N	91	102	532	0.71	0.9	17.0	900	-	651	620	0.83	3.2	15.0	28	-	-
12/9/72																						
15A	270	S_4	12	1,2,3,4	70/0	L	86	89	643	0.86	2.6	16.2	59	-	640	415	0.55	3.3	15.6	173	-	-
12/11/72																						
1	320	S_1	16	None	70/-	N	120	120	902	1.20	3.6	16.0	22	2	659	799	1.07	3.6	15.6	23	2	696
5A	320	S_3	14	2,3	70/70	N	102	105	728	0.97	3.1	15.0	32	-	659	565	0.88	3.6	14.5	34	-	688
10	320	S_3	14	2,3	70/70	L	109	97	566	0.75	1.8	15.3	75	1	651	522	0.70	2.2	14.9	90	1	680
12/12/72																						
26B	350	S_1	16	None	70/-	N	117	119	888	1.18	3.2	14.8	19	4	671	801	1.06	3.5	14.4	19	4	703
12/13/72																						
6	320	S_1	16	None	70/-	L	112	112	804	1.07	2.4	15.8	80	-	651	630	0.84	2.4	15.6	140	-	-
7	310	S_2	14	1,4	70/0*	L	96	100	788	1.05	2.0	15.8	47	-	650	565	0.75	2.5	15.2	220	-	-
8	314	S_2	14	1,4	70/70	L	96	110	772	1.03	1.9	15.2	29	-	658	591	0.79	4.5	13.3	32	-	-
12/14/72																						
16	250	S_4	12	1,2,3,4	70/70	L	91	90	661	0.88	3.8	14.2	29	-	600	411	0.55	3.7	14.1	94	-	643
3/19/73																						
14R	272	S_1	16	None	70/70	L	110	100	754	1.01	2.0	15.7	44	-	616	640	0.85	2.2	15.6	175	-	661
11R	272	S_1	16	None	70/70	N	120	122	840	1.12	3.7	14.3	45	-	617	748	1.00	3.9	14.1	46	-	663
16R	272	S_4	12	1,2,3,4	70/70	L	82	94	560	0.75	1.8	15.5	396	-	611	472	0.63	4.5	13.1	131	-	653
25R	272	S_5	12	2,3,5,8	70/70	L	88	88	647	0.86	3.1	13.8	372	-	-	484	0.65	3.1	13.9	372	-	651
3/20/73																						
1R	315	S_1	16	None	70/70	N	119	116	916	1.22	3.4	15.0	56	-	647	765	1.02	3.0	15.3	60	-	682
6R	320	S_1	16	None	70/70	L	114	110	862	1.15	2.6	15.7	66	-	638	660	0.88	2.1	16.0	230	-	676
8R	321	S_2	14	1,4	70/70	L	102	97	738	0.98	3.1	15.2	87	-	643	526	0.70	2.2	15.9	902	-	683
10R	320	S_3	14	2,3	70/70	L	104	102	802	1.07	3.5	14.9	66	-	643	593	0.79	3.0	15.1	218	-	681

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(1) Excess air target: N-Normal, L-Low Excess Air.

* Position of idle registeew was uncertain.

** Hydrocarbons were measured on each test but values were negligible except where indicated.

TABLE 5

SUMMARY OF OPERATING AND EMISSION DATA - HARLLEE BRANCH, BOILER NO. 3

(480 MW, Horizontal Opposed Wall, Pulverized Coal Fired)

	Boiler Operating Conditions							Average Gaseous Emissions and Temperatures						
		Firing Pattern			Secondary	Excess Air		NO_x		O_2	CO_2	CO	HC*	Temp.
			Burners											
Date and Run No.	Gross Load (MW)	Code	No. on Coal	No. on Air	Air Registers % Open	Target	% Stoic. To Act. Burners	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	%	%	PPM (3% O_2, Dry)	PPM (3% O_2, Dry)	°F
5/22/72														
1	478	S_1	40	0	100	Nor.	119	747	0.99	3.5	14.1	21	-	604
2	480	S_1	40	0	100	Low	107	549	0.73	1.4	16.6	81	1	595
5/23/72														
3	480	S_1	40	0	50	Nor.	120	735	0.98	3.7	14.8	13	0	613
4	478	S_1	40	0	50	Low	110	667	0.89	2.0	16.3	26	-	596
5	480	S_2	36	4	100	Nor.	105	613	0.82	3.1	14.8	26	-	600
6	477	S_2	36	4	50	Low	98	569	0.76	1.9	15.9	30	-	596
7	480	S_3	36	4	50	Nor.	107	734	0.98	3.4	15.3	24	-	610
8	478	S_3	36	4	100	Low	99	578	0.77	2.0	16.7	45	1	596
5/24/72														
9	485	S_3	36	4	100	Nor.	104	680	0.90	2.9	15.6	18	1	610
10	479	S_3	36	4	50	Low	95	568	0.75	1.3	17.0	38	-	593
11	480	S_2	36	4	50	Nor.	108	624	0.83	3.6	14.7	24	2	614
12	478	S_2	36	4	100	Low	97	493	0.66	1.7	16.9	52	-	595
1A	500	S_1	40	0	100	Nor.	120	688	0.92	3.6	15.4	27	-	619
5/31/72														
20	398	S_4	30	10	100	Low	81	372	0.49	1.6	16.6	178	-	567
14	400	S_5	30	10	100	Low	80	334	0.44	1.5	15.5	924	-	551
28	398	S_6	30	10	100	Low	80	392	0.52	1.4	15.6	92	-	560
23	397	S_7	30	10	100	Low	79	256	0.47	1.1	16.3	562	-	558
1B	500	S_1	40	0	100	Nor.	123	707	0.94	4.1	14.5	32	-	620
6/1/72														
40	392	S_8	34	6	100	Low	92	363	0.48	1.7	16.4	159	-	554
41	399	S_{10}	34	6	100	Low	93	339	0.45	1.9	16.2	75	-	560
42	400	S_{11}	34	6	100	Low	94	360	0.47	2.0	15.8	225	-	558
29	399	S_1	40	0	100	Nor.	116	537	0.71	3.0	15.0	28	-	565
1C	490	S_1	40	0	100	Nor.	116	668	0.89	3.0	15.2	47	-	606
6/12/72														
1D	488	S_1	40	0	100	Nor.	120	711	0.95	3.7	14.3	14	-	624
6/13/72														
43	445	S_{14}	35	5	100	Low	94	491	0.65	1.5	16.4	96	-	590
6/14/72														
44	481	S_{12}	35	5	100	Low	94	576	0.77	1.4	17.2	280	-	601
45	480	S_{15}	36	4	100	Low	95	594	0.79	1.2	17.0	187	-	595
46	485	S_{13}	36	4	100	Low	96	624	0.83	1.4	17.1	147	-	598
47	482	S_{2*}	35	5	100	Low	95	589	0.78	1.8	16.4	172	-	593
1E	483	S_1	40	0	100	Nor.	116	745	0.99	3.0	15.4	23	-	609
6/15/72														
48	275	S_{16}	32	8	100	Low	92	287	0.38	2.9	15.9	417	-	524
49	155	S_{17}	20	8	100	Low	67	148	0.20	2.4	16.2	306	-	460
6/19/72														
50	475	S_{18}	36	4	100	Low	96	486	0.65	1.4	17.1	618	-	600
51	472	S_{19}	35	5	100	Low	94	493	0.65	1.5	16.9	321	-	596
52	471	S_{20}	34	6	100	Low	91	466	0.62	1.4	16.8	357	-	592
6/27/72														
16	477	S_{20}	34	6	100	Low	90	463	0.62	1.2	17.3	127	-	613
6/28/72														
1H	465	S_{20}	34	6	100	Low	90	472	0.63	1.3	17.2	24	-	611
7/5/72														
52A	482	S_{20}	34	6	100	Low	91	517	0.69	1.4	17.4	158	-	614
7/11/72														
52B	467	S_{20}	34	6	100	Low	91	520	0.69	1.5	17.1	45	2	611
7/12/72														
52C	475	S_{20}	34	6	100	Low	91	466	0.62	1.5	17.1	45	0	605
7/13/72														
52D	475	S_{20}	34	6	100	Low	93	582	0.77	1.9	16.0	122	3.1	610
7/14/72														
52E	465	S_{20}	34	6	100	Low	94	565	0.75	2.0	16.4	101	1.2	606
7/17/72														
53A	450	S_{21}	35	5	100	Low	94	552	0.73	1.7	17.3	20	1.2	597
7/18/72														
53B	450	S_{21}	35	5	100	Low	94	592	0.79	1.6	16.6	28	2	591
7/24/72														
52F	477	S_{20}	34	6	100	Low	89	403	0.54	1.1	17.3	288	3	603
7/25/72														
52G	465	S_{20}	34	6	100	Low	91	407	0.54	1.5	16.6	47	1.9	604
7/26/72														
53D	465	S_{21}	35	5	100	Low	96	556	0.74	2.1	16.5	52	2.1	607
7/27/72														
1J	455	S_{22}	39	1	100	Nor.	112	608	0.81	2.8	16.4	20	2.5	603
1K	455	S_{22}	39	1	100	Nor.	113	639	0.85	3.0	15.5	26	2.1	605
7/28/72														
42I	478	S_{11}	34	6	100	Low	92	498	0.66	1.6	16.1	48	1.9	603

* Hydrocarbons were measured on each test but values were negligible except where indicated.

TABLE 6

SUMMARY OF OPERATING AND EMISSIONS DATA - LELAND OLDS, BOILER NO. 1

(218 MW, Horizontally Opposed, Pulverized Coal Fired Boiler)

	Boiler Operating Conditions						Average Gaseous Emissions and Temperatures					
		Firing Pattern			Excess Air		NO$_x$		O$_2$	CO$_2$	CO	Temp.
Date and Run No.	Gross Load MW	Code [1]	Firing	Air Only	Target	% Stoic. To Act. Burners	PPM (3% O$_2$, Dry)	Pounds Per 10^6 BTU	%	%	PPM (3% O$_2$ Dry)	°F
7/6/73												
1	219	S_1	20	0	Nor.	122	569	0.74	3.9	15.7	24	954
2	218	S_1	20	0	Low	110	447	0.58	2.1	16.9	283	948
7/9/73												
3	218	S_2	18	2	Nor.	112	560	0.74	4.2	14.9	23	945
4	216	S_2	18	2	Low	104	375	0.50	2.8	16.3	231	937
5	192	S_3	16	4	Low	95	342	0.45	3.5	15.9	139	883
7/10/73												
6	187	S_4	16	4	Nor.	103	428	0.57	4.9	14.4	21	910
7	185	S_4	16	4	Low	89	260	0.35	2.2	16.8	518	981
9	185	S_5	16	4	Low	91	329	0.44	2.6	15.9	226	922
11	180	S_6	16	4	Low	95	256	0.47	3.5	15.9	153	880
1A	214	S_1	20	0	Nor.	120	564	0.75	3.6	15.6	21	947
7/11/73												
4A	205	S_7	18	2	Low	103	418	0.56	2.6	16.3	50	935
4B	205	S_7	18	2	Low	103	401	0.53	2.7	16.4	51	990
7/12/73												
4C	205	S_7	18	2	Low	105	475	0.63	3.1	16.0	25	918

NOTE: Hydrocarbons were measured on each test but values were negligible except where indicated.

TABLE 7

SUMMARY OF OPERATING AND EMISSION DATA - FOUR CORNERS, BOILER NO. 4

(800 MW, Horizontally Opposed, Pulverized Coal Fired)

	Boiler Operating Conditions							Average Gaseous Emissions and Temperature					
		Firing Pattern			Second.	Excess Air		NO_x		O_2	CO_2	CO	Temp.
			Burners										
Date and Run No.	Gross Load (MW)	Code [1]	Firing	Air Only	Air Registers % Open	Target	% Stoic. To Act. Burners	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	%	%	PPM (3% O_2, Dry)	°F
11/2/72													
19	600	S_5	42	0	100	Nor.	112	816	1.08	6.5	11.0	17	-
20	600	S_5	42	12	100	Nor.	111	801	1.07	6.4	11.0	13	544
21	590	S_5	42	12	100	Low	90	452	0.60	3.0	14.3	33	514
11/3/72													
1A	750	S_1	54	0	100	High	135	982	1.31	5.6	11.7	24	472
6A	755	S_1	54	0	100	Low	112	641	0.85	2.3	14.6	156	560
11/5/72													
1	740	S_1	54	0	100	Nor.	127	848	1.13	4.6	13.8	18	582
2	710	S_1	54	0	50	Low	113	659	0.88	2.5	14.6	110	554
3	730	S_2	46	8	50	Nor.	108	695	0.92	4.6	12.5	24	-
4	730	S_2	46	8	100	Low	95	482	0.64	2.2	14.4	260	551
11/7/72													
5	760	S_1	54	0	50	Nor.	130	932	1.24	5.0	13.5	14	588
2B	750	S_1	54	0	50	Low	115	748	0.99	2.8	15.0	60	592
8	730	S_2	46	8	50	Low	101	609	0.81	3.3	13.1	113	564
7	730	S_2	46	8	100	Nor.	108	754	1.00	4.7	13.8	19	578
11/8/72													
6	754	S_1	54	0	100	Low	110	630	0.84	2.0	15.9	423	552
1B	768	S_1	54	0	100	Nor.	131	965	1.28	5.1	13.5	15	578
11/9/72													
1C	810	S_1	54	0	100	Nor.	126	843	1.12	4.5	13.5	19	576
1D	796	S_1	54	0	100	Nor.	132	949	1.26	5.2	12.6	13	585
11/10/72													
9	801	S_3	46	8	100	Nor.	108	685	0.91	4.6	13.9	48	580
14	794	S_3	46	8	100	Low	95	494	0.66	2.3	15.6	453	550
15	806	S_4	42	12	100	Nor.	105	709	0.94	5.5	12.6	21	590
12	794	S_4	42	12	100	Low	91	488	0.65	3.2	14.6	172	560
11/14/72													
1E*	755	S_1	54	0	100	Nor.	119	741	0.99	3.4	14.8	21	587
11/15/72													
1F*	775	S_1	54	0	100	Nor.	117	715	0.95	3.1	15.3	14	575
11/18/72													
12A	725	S_4	42	12	100	Nor.	97	560	0.74	4.3	13.9	40	558
11/20/72													
12B*	704	S_2	44	8	100	Low	98	458	0.61	3.7	14.4	40	540
11/21/72													
12C*	735	S_2	46	8	100	Low	98	473	0.63	2.8	15.0	195	563

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[1] Firing Pattern:

Symbols		Burners on Air Only
S_1	○	None
S_2	□	1NT, 9NT, 1ST, 9ST, 5NT, 6NT, 5ST, and 6ST.
S_3	△	1NT, 1NM, 9ST, 9SM, 6NT, 6NM, 5ST, and 5SM.
S_4	▽	1NT, 9NT, 1ST, 9ST, 8NT, 2ST, 5NT, 6NT, 5ST [illegible], 7NT and 3ST.
S_5	⬡	Burners fed by pulverizers 5 and 9.

* 100-200 gal./hour water injection into furnace.

NOTE: Hydrocarbons were measured on each test but values were negligible except where indicated.

TABLE 8

SUMMARY OF OPERATING AND EMISSION DATA - BARRY, BOILER NO. 3

(250 MW, Pulverized Coal, Tangentially Fired)

	Boiler Operating Conditions*								Average Gaseous Emissions & Temp.					
		Firing Pattern					Excess Air		NO_x		O_2	CO_2	CO	Temp.
Date and Run No.	Gross Load (MW)	Code **	Burners No. on Coal	Burners No. on Air	Secondary Air Reg. Aux/Coal (% Open)	Mill Fineness	Target	% Stoic. To Act. Burners	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	%	%	PPM (3% O_2, Dry)	°F
3/23/73														
1	250	S_1	48	0	100/30	Nor.	Nor.	117	410	0.54	3.1	14.8	61	662
2	248	S_1	48	0	100/30	Nor.	Low	106	310	0.41	1.3	16.2	100	646
3	248	S_1	48	0	40/100	Nor.	Nor.	117	425	0.56	3.2	14.2	60	666
4	248	S_1	48	0	40/100	Nor.	Low	109	350	0.46	1.9	15.2	115	648
5	250	S_1	48	0	40/100	Coarse	Low	110	350	0.46	2.0	14.9	130	654
6	250	S_1	48	0	40/100	Coarse	Nor.	119	420	0.56	3.5	13.3	64	666
7	251	S_1	48	0	100/30	Coarse	Nor.	119	416	0.55	3.5	13.1	77	663
8	248	S_1	48	0	100/30	Coarse	Low	107	512	0.41	1.4	14.4	129	645

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* Tilts welded into fixed position.

** Only normal firing runs because of mechanical problems.

NOTE: Hydrocarbons were measured on each test but values were negligible except where indicated.

TABLE 9

SUMMARY OF OPERATING AND EMISSION DATA - NAUGHTON, BOILER NO. 3

(330 MW, Tangential, Pulverized Coal Fired Boiler)

	Boiler Operating Conditions								Average Gaseous Emissions and Temperature						
		Firing Pattern			Secondary	Burner	Excess Air		NO_x		O_2	CO_2	HC***	CO	Temp.
	Gross		Burners		Air	Tilt									
Date and Run No.	Load (MW)	Code	No. on Coal	No. on Air	Registers Aux./coal	(° From Horiz.)	Target	% Stoic. To Act. Burners	PPM (3% O_2, Dry)	Lbs. Per 10^6 BTU	%	%	PPM (3% O_2, Dry)	PPM (3% O_2, Dry)	°F
9/13/72					(% Open)			**							
1	256	S_1	20	0	20-80	0	Nor.	127	537		4.9	12.9	-	30	694
9/14/72															
2	260	S_2	16	4	20-80	0	Nor.	99	304		4.9	13.5	1	14	693
3	265	S_2	16	4	20-80	0	Low	91	265		3.6	14.2	1	62	673
4	254	S_2	16	4	20-80	-30	Low	92	266		3.7	14.0	1	28	666
5	260	S_2	16	4	20-80	+10	Low	92	284		3.6	13.7	1	23	672
9/18/72															
6	250	S_2	16	4	20-90	-30	Low	91	216		3.1	14.5	1	210	666
7	262	S_2	16	4	70-25	-30	Low	92	213		3.0	16.0	1	78	504
8	260	S_2	16*	4	70-25	-30	Low	93	251		3.2	15.9	1	82	666
9	262	S_2	16*	4	15-90	-30	Low	92	245		3.1	16.4	1	91	682
9/19/72															
10	256	S_2	16	4	60-20	0	Low	88	197		3.0	16.8	1	376	670
11	259	S_2	16	4	60-20	+22	Low	90	216		3.5	16.4	1	354	673
12	260	S_2	16*	4	60-20	+20	Low	90	273		3.7	15.9	1	306	674
13	260	S_2	16*	4	60-20	0	Low	91	235		3.7	16.0	1	208	672
9/20/72															
14	199	S_1	16	0	20-80	0	Nor.	118	458		4.2	14.6	-	20	626
15	198	S_3	12	4	20-80	0	Nor.	78	169		4.5	13.4	-	27	631
16	200	S_3	12	4	20-80	0	Low	74	182		3.2	13.7	-	56	622
17	199	S_3	12	4	70-30	0	Low	65	176		4.2	12.7	-	102	636
9/21/72															
18	328	S_1	20	0	20-80	0	Nor.	121	494		3.9	14.7	-	30	755
19	328	S_1	20	0	20-80	0	Low	109	379		2.1	15.8	-	225	732
20	308	S_2	16	4	20-80	0	Low	88	236		2.7	14.5	-	44	715
21	310	S_2	16	4	70-30	0	Low	77	219		2.3	14.8	-	499	714
9/27/72															
22	275	S_2	16	4	20-80	0	Nor.	105	331		3.1	15.2	-	185	686
10/4/72															
23	283	S_1	20	0	20-70	-30	Nor.	120	510		3.6	15.3	-	21	702
10/6/72															
24	300	S_1	20	0	20-80	-30	Nor.	120	569		3.6	15.3	-	19	721
10/9/72															
25	315	S_1	20	0	20-80	-30	Nor.	124	549		4.2	14.0	-	18	763
10/10/72															
26	340	S_1	20	0	20-80	0	Nor.	125	568		4.4	14.2	-	24	757

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* Mill fineness set to coarse (1 vs. 2.1)

** Calculated by combustion engineering from air register openings and total air.

*** Hydrocarbons were measured on each test but values were negligible except where indicated.

TABLE 10

SUMMARY OF OPERATING AND EMISSION DATA - DAVE JOHNSTON, BOILER NO. 4

(340 MW, Pulverized Coal, Tangentially Fired)

	Boiler Operating Conditions								Average Gaseous Emissions & Temp.					
		Firing Pattern			Excess Air				NO_x		O_2	CO_2	CO	Temp.
			Burners											
Date and Run No.	Gross Load (MW)	Pulv. Off	No. on Coal	No. on Air	Target	% Stoic. To Act. Burners	Burner Tilt (° From Horiz.)	Primary Air Level	PPM (3% O_2 Dry)	Pounds Per 10^6 BTU	%	%	PPM (3% O_2 Dry)	°F
8/8/73														
1	306	17 & 20	20	0	Nor.	124	0°	Low	434	0.58	4.2	14.6	19	780
2	303	17 & 20	20	0	Low	117	0°	Low	386	0.51	3.2	16.2	56	700
3	303	17 & 20	20	0	Low	117	-10°	Low	414	0.55	3.2	16.0	28	750
4	305	17 & 20	20	0	Low	119	+16°	Low	381	0.51	3.4	15.6	142	765
8/9/73														
10	310	17 & 21	20	0	Nor.	122	0°	+10%	362	0.48	3.9	12.3	41	775
17	312	17 & 21	20	0	Nor.	122	-10°	+10%	380	0.50	3.9	13.3	40	780

NOTE: Hydrocarbons were measured on each test but values were negligible except where indicated.

TABLE 11

SUMMARY OF OPERATING AND EMISSION DATA - BARRY, BOILER NO. 4

(360 MW, Tangential, Pulverized Coal Fired)

	Boiler Operating Conditions								Average Gaseous Emissions and Temperature					
		Firing Pattern			Secondary	Burner	Excess Air		NO_x		O_2	CO_2	CO	Temp.
			Burners		Air Reg.	Tilt								
Date and Run No.	Gross Load (MW)	Code	No. on Coal	No. on Air	Aux./Coal (% Open)	(° From Horiz.)	Target	% Stoic. To Act. Burners	PPM (3% O_2, Dry)	Pounds Per 10^6 BTU	%	%	PPM (3% O_2, Dry)	(°F)
1/19/73														
13	325	AS_1	20	0	100/50	0	Nor.	115	420	0.56	4.7	13.4	20	308
29	328	AS_1	20	0	100/50	0	Low	107	336	0.45	2.8	15.4	227	311
30	330	AS_1	20	0	100/50	+20	Low	110	364	0.48	3.6	14.5	37	310
31	330	AS_1	20	0	50/100	-30	Low	107	398	0.53	2.8	15.2	41	312
1/22/73														
17	290	BCS_1	20	0	100/50	0	Nor.	118	441	0.59	5.1	11.5	19	305
18	295	BCS_2	16	4	100/50	0	Nor.	100	334	0.44	6.3	12.3	33	295
19	292	BCS_2	16	4	100/50	0	Low	94	288	0.38	4.9	12.5	50	295
20	281	BCS_2	16	4	50/100	-30	Low	86	273	0.36	3.1	13.3	43	289
32	286	BCS_2	16	4	50/100	0	Low	94	282	0.51	5.0	11.9	50	292
1/23/73														
1	348	ACS_1	20	0	100/50	0	Nor.	115	415	0.55	4.4	13.8	24	305
2	348	ACS_1	20	0	100/50	0	Low	112	398	0.53	3.9	13.8	115	290
3	344	ACS_1	20	0	100/50	+15	Low	110	349	0.46	3.6	13.8	100	295
4	334	ACS_1	20	0	50/100	-25	Low	106	364	0.48	2.5	14.0	96	291
5	299	ACS_2	16	4	100/50	0	Nor.	96	313	0.42	5.4	11.5	26	281
6	298	ACS_2	16	4	100/50	0	Low	94	286	0.38	4.8	12.2	63	280
7	294	ACS_2	16	4	100/50	+15	Low	92	294	0.39	4.4	12.1	98	288
8	294	ACS_2	16	4	50/100	-30	Low	85	257	0.34	2.4	15.9	107	284
1/24/73														
33	346	ACS_1	20	0	100/50	-30	Nor.	114	497	0.64	4.3	14.4	27	308
34	345	ACS_1	20	0	100/50	-30	Low	108	445	0.59	3.1	15.4	24	308
35	360	ACS_1	20	0	100/50	0	Low	112	409	0.54	3.8	14.0	169	310
37	348	ACS_1	20	0	100/20	0	Low	112	441	0.59	3.9	13.7	58	309
9	322	ACS_2	16	4	50/100	0	Low	92	295	0.39	4.4	13.0	97	291
10	297	ACS_2	16	4	100/50	-30	Low	86	289	0.38	3.0	14.1	113	286
11	311	ACS_2	16*	4	100/50	-30	Low	86	299	0.40	2.9	14.5	114	288
12	304	ACS_2	16*	4	50/100	0	Low	91	297	0.40	4.3	13.3	189	285
2/4/73														
40	186	BS_3	12	4	100/50	0	Nor.	100	338	0.45	7.7	10.5	22	273
41	180	BS_3	12	4	100/50	0	Low	84	200	0.27	3.9	14.1	211	254
25	210	BCS_1	20	0	50/100	0	Nor.	123	440	0.58	6.0	11.6	27	266
26	186	BCS_4	12	4	100/50	0	Low	83	189	0.25	3.7	13.7	281	249
27	184	BCS_4	12	4	100/50	0	Nor.	97	261	0.35	7.1	10.6	30	255
28	180	BCS_4	12	4	100/50	-30	Low	86	232	0.31	4.3	13.1	43	250
2/5/73														
13A	343	AS_1	20	0	100/50	0	Nor.	112	415	0.55	3.8	14.6	25	315
14	292	AS_2	16	4	100/50	0	Nor.	90	309	0.41	5.1	13.1	25	298
15	284	AS_2	16	4	100/50	0	Low	88	245	0.33	3.6	14.0	201	290
16	283	AS_2	16	4	50/100	-15	Low	87	264	0.35	3.3	14.5	58	277
2/7/73														
42	320	ACS_1	20	0	32/50	-8	Nor.	112	396	0.53	3.8	13.4	56	305
43	325	ACS_1	20	0	32/50	-8	Nor.	107	349	0.46	2.7	14.0	395	303
2/9/73														
50	323	ACS_1	16	0	40/50	-8	Nor.	115	436	0.58	4.4	14.6	37	291
2/13/73														
19A	283	BCS_2	16	4	100/50	-8	Low	92	347	0.46	4.6	15.9	48	283
2/14/73														
19B	255	BCS_2	16	4	100/50	-8	Low	91	288	0.38	4.3	14.1	49	290
2/21/73														
19C	282	BCS_2	16	4	100/50	-8	Low	95	338	0.45	5.2	12.7	21	293
19D	280	BCS_2	16	4	100/50	-8	Low	87	258	0.34	3.3	13.5	177	281
19E	289	BCS_2	16	4	30/50	-8	Low	90	276	0.37	3.9	13.0	130	282
19F	288	BCS_2	16	4	50/20	-8	Low	91	274	0.36	4.2	12.6	69	280
2/22/73														
42A	293	BCS_1	16	0	100/50	-8	Nor.	117	396	0.53	5.0	13.2	36	280
2/23/73														
42B	283	BCS_2	16	0	100/50	-8	Nor.	115	370	0.49	4.5	14.2	47	215

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* Coarse mill setting.

NOTE: Hydrocarbons were measured on each test but values were negligible except where indicated.

TABLE 12

SUMMARY OF OPERATING AND EMISSION DATA - BIG BEND BOILER NO. 2

(450 MW, Turbo-Furnace, Pulverized Coal Fired)

	Boiler Operating Conditions							Average Gaseous Emissions and Temperature					
				Firing Pattern		Excess Air		NO_x		O_2	CO_2	CO	Temp.
				Burners									
Date and Run No.	Gross Load (MW)	Direct Vanes Front/Rear	Ash Inject.	No. on Coal	No. on Air	Target	% Stoic. To Act. Burners	PPM (3%, O_2 Dry)	Pounds Per 10^6 BTU	%	%	PPM (3% O_2, Dry)	°F
3/5/73													
6	225	-15/+15	Yes	24	0	Nor.	119	370	0.49	3.4	15.0	19	596
4A	375	-15/+15	Yes	24	0	Nor.	115	547	0.73	2.8	15.4	24	672
4B	380	-15/+15	No	24	0	Nor.	115	558	0.74	2.9	15.2	23	659
3/6/73													
2	370	-15/-15	No	24	0	Nor.	115	587	0.78	2.8	15.3	30	703
1	370	-15/-15	Yes	24	0	Nor.	115	614	0.82	2.8	15.3	25	724
3	370	-15/-15	No	24	0	Low	110	464	0.62	2.0	15.9	32	672
5	370	-15/+15	No	24	0	Low	107	398	0.53	1.4	16.2	319	665
3/7/73													
20*	230	-15/+15	No	16	0	Nor.	119	350	0.46	3.4	15.0	21	587
21**	230	-15/+15	No	16	4	Low	99	347	0.46	3.4	14.9	24	587
22***	230	-15/+15	No	16	8	Low	79	312	0.41	3.5	14.6	199	590
3/12/73													
9	300	-15/+15	No	24	0	Nor.	115	378	0.50	2.9	14.6	24	633
10	300	-15/+15	No	24	0	Low	109	341	0.45	1.8	15.1	87	608
11	300	-15/+15	No	24	0	Nor.	113	397	0.53	2.5	14.2	53	635
12	300	-15/+15	No	24	0	Low	110	362	0.48	2.1	14.4	376	632

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* B mill off - secondary air dampers closed on idle burners.

** B mill off - secondary air dampers open on 1/2 of idle burners.

*** B mill off - secondary air dampers open on all idle burners.

NOTE: Hydrocarbons were measured on each test but values were negligible except where indicated.

APPENDIX B

Coal Analyses

Representative coal samples were taken for each major test under baseline and "low NO_x" operating conditions. The samples were submitted to the Exxon Research and Engineering Company's Coal Analysis Laboratory at Baytown, Texas for analysis. Ultimate analysis determinations, which were of most importance to the study, were made on all samples as indicated in the following tables for each boiler tested. Proximate analyses information are also tabulated, where available. Ash fusion temperature determinations under reducing and oxidizing conditions and analyses for critical coal ash elements were obtained on coal samples taken during certain important tests in an attempt to shed more light on potential slagging or fouling side effects of "low NO_x" firing techniques.

All coal analyses data, which were used for making various calculations in this report, are tabulated in Tables 1-10 of Appendix B.

APPENDIX B

TABLE 1

COAL ANALYSES

TENNESSEE VALLEY AUTHORITY
WIDOWS CREEK STATION - UNIT NO. 6

Run No.	1	1A	10	10-A-1	10-C-1	10-C-3	10-C-5	1-B	26-A-1	26-A-3
Proximate Analysis										
Moisture	6.3	5.4	5.6	8.7	7.2	7.7	8.5	5.1	8.8	7.5
Ash										
Voaltiles										
Fixed Carbon										
Sulfur										
BTU/LB.										
Ultimate Analysis										
C - % Dry	66.06	71.11	71.22	66.22	69.01	67.27	65.68	67.48	66.28	67.79
H - % Dry	4.13	4.54	4.46	4.60	4.97	4.63	4.48	4.36	4.55	4.46
S - % Dry	0.82	0.81	0.96	4.04	4.00	3.09	3.70	1.36	3.36	2.40
N - % Dry	1.29	1.40	1.39	1.31	1.43	1.37	1.33	1.35	1.36	1.72
Cl - % Dry										
O - % Dry	5.82	5.36	5.88	7.56	8.39	8.06	7.29	6.05	7.58	6.37
Ash - % Dry	21.88	16.78	16.08	16.28	12.20	15.58	17.53	19.38	16.87	17.27
BTU/LB. - % Dry	11,739	12,106	12,689	12,068	12,646	12,168	11,919	12,094	12,019	12,218
Ash Fusion Temperature										
Reducing										
Int.	2450	2350	2460	1975	2000	2085	2025	2450	2025	2130
H=W	2700	2600	2675	2035	2070	2160	2110	2660	2120	2400
H=W/2	2700	2625	2700	2055	2130	2190	2125	2700	2140	2430
Fl.	2700	2680	2700	2140	2300	2250	2165	2700	2200	2460
Oxidizing										
Int.	2475	2400	2500	2360	2340	2450	2225	2500	2450	2590
H=W	2700	2700	2700	2500	2515	2535	2500	2700	2500	2635
H=W/2	2700	2700	2700	2510	2525	2560	2520	2700	2525	2665
Fl.	2700	2700	2700	2515	2545	2570	2525	2700	2590	2670

APPENDIX B

TABLE 2

COAL ANALYSES

GEORGIA POWER COMPANY
HARLLEE BRANCH STATION - UNIT NO. 3

Run No.	1	1-A	1-C	1-D	1-E	1-G	1-H	52	52-A	52-B	52-C	52-D	52-E
Proximate Analysis													
Moisture	7.9	6.31	5.1	5.82	7.86	6.92	7.58	7.4	5.07	5.86	6.98	13.92	7.01
Ash													
Volatiles													
Fixed Carbon													
Sulfur													
BTU/LB.													
Ultimate Analysis													
C - % Dry	72.15	73.27	71.69	74.17	73.94	72.53	75.39	73.96	75.37	73.89	73.34	72.40	71.50
H - % Dry	4.78	4.89	4.93	5.01	4.89	4.93	5.06	4.96	5.07	4.97	4.96	4.85	4.77
S - % Dry	1.12	1.16	1.65	1.27	1.12	1.51	1.41	1.61	1.08	1.25	1.09	1.24	1.32
N - % Dry	1.71	1.76	1.71	1.84	1.78	1.81	1.93	1.87	1.82	1.77	1.77	1.74	1.40
Cl - % Dry													
O - % Dry	8.23	7.63	7.34	7.39	8.97	7.10	7.09	6.53	7.29	7.18	7.79	7.81	8.26
Ash - % Dry	12.02	11.30	12.70	10.32	9.31	12.12	9.12	11.07	9.44	10.94	11.05	11.96	12.76
BTU/LB. - % Dry	12,874	13,147	12,972	13,367	13,155	13,108	13,605	13,309	13,576	13,315	13,185	12,986	12,783
Ash Fusion Temperature													
Reducing													
Int.	2175	2300	2140	2150	2475	2250	2400	2200	2350	2325	2330	2270	2360
H=W	2625	2450	2400	2425	2500	2450	2500	2400	2450	2480	2490	2475	2600
H=W/2	2700	2475	2415	2450	2520	2470	2515	2450	2465	2525	2510	2500	2630
Fl	2700	2600	2450	2600	2530	2500	2570	2475	2550	2600	2540	2530	2695
Oxidizing													
Int.	2550	2500	2375	2275	2520	2615	2525	2420	2575	2595	2600	2700	2700
H=W	2700	2700	2660	2690	2700	2656	2700	2640	2700	2700	2700	2700	2700
H=W/2	2700	2700	2675	2700	2700	2685	2700	2670	2700	2700	2700	2700	2700
Fl.	2700	2700	2685	2700	2700	2700	2700	2690	2700	2700	2700	2700	2700

APPENDIX B

TABLE 3

COAL ANALYSES

UTAH POWER AND LIGHT CO.
NAUGHTON STATION, BOILER NO. 3

Run Number	18	19	20	21	22	23	25	26
Date - 1972	9-21	9-21	9-21	9-21	9-27	--	10-9	10-10
Raw Coal Sample								
Moisture, %	23.55				--	24.41	22.98	22.91
Hardgrove Grindability	53.4				--	49.5	54.9	51.6
Pulverized Coal Sample **Proximate Analysis**								
Moisture	12.23	10.97	13.38	13.57	14.35	11.55	13.40	13.99
Ash	5.47	5.78	6.19	6.39	8.80	8.16	6.78	8.10
Volatiles	39.12	39.57	38.23	38.04	36.53	38.78	37.75	36.61
Fixed Carbon	43.18	43.68	42.20	42.00	40.32	41.51	42.07	41.30
Btu/lb	10,566	10,688	10,326	10,276	9,866	10,293	10,273	9,992
Ultimate Analysis								
C, % Dry	70.06	69.86	69.37	69.19	67.04	67.62	69.14	67.61
H, % Dry	4.89	4.88	4.85	4.83	4.68	4.71	4.83	4.75
S, % Dry	0.49	0.48	0.51	0.59	0.55	0.68	0.63	0.63
N, % Dry	1.47	1.57	1.58	1.53	1.60	1.64	1.65	1.57
Cl, % Dry	0.01	0.01	0.01	0.01	0.01	.01	0.01	0.01
O, % Dry	16.47	16.42	16.30	16.26	15.76	16.11	15.91	16.01
Ash, % Dry	6.23	6.49	7.15	7.39	10.27	9.23	7.83	9.42

APPENDIX B

TABLE 4

COAL ANALYSES

ARIZONA PUBLIC SERVICE CO.
FOUR CORNERS STATION, BOILER NO. 4

Run No.	12A	621B	1C&1D	1A&6A	19,20,21	1,2,3,4	1E	12B	1F
Lab. No.	1-14B	1-15A	1-15A	1-17A	1-18A	1-18A	1-19A	1-23B	1-16B
Date, 1972	11-18	11-8	11-9	11-3	11-2	11-5	11-14	11-21	11-15
Pulverized Coal Proximate Analysis									
Moisture, %	11.71	12.70	12.88	13.97	14.05	13.29	12.91	13.10	12.79
Ash	23.13	21.35	21.86	21.01	21.18	20.61	21.92	21.12	21.96
Volatiles	31.47	31.35	31.02	30.91	30.79	31.42	30.88	31.21	30.68
Fixed Carbon	33.69	34.60	34.24	34.11	33.98	34.68	34.29	34.57	34.57
Btu/lb.	8,913	8,947	8,801	8,763	8,787	8,944	8,821	8,915	8,811
Ultimate Analysis									
C, % Dry	56.95	58.05	57.51	58.67	57.69	58.43	57.50	58.15	57.28
H, % Dry	4.34	4.35	4.25	4.26	4.32	4.34	4.30	4.31	4.27
S, % Dry	0.75	0.79	0.75	0.85	0.80	0.70	0.76	0.81	0.67
N, % Dry	1.23	1.23	1.31	1.24	1.26	1.29	1.26	1.24	1.29
Cl, % Dry	0.01	--	--	--	--	--	0.01	0.01	0.01
O, % Dry	10.53	11.11	11.10	11.16	11.04	11.47	11.00	11.18	11.30
Ash, % Dry	26.19	24.46	25.09	24.42	24.93	23.77	25.17	24.30	25.18

APPENDIX B

TABLE 5

COAL ANALYSES*

GULF POWER COMPANY
CRIST STATION, BOILER NO. 6

Laboratory No	M15901	M15898	M15903	M15691
Run No	2&3	26	4&5	1,5A,10&26B
Date	Dec 6-72	Dec 7-72	Dec 8-72	Dec 11-12,72
PROXIMATE ANALYSIS				
Moisture	9.24	10.47	8.13	9.6
Ash	8.50	12.04	8.49	10.2
Volatiles	36.76	33.06	37.57	-
Fixed Carbon	45.5	44.43	45.81	-
Sulfur	-	-	-	-
BRU/Lb.	11,855	11,282	11,920	11,186
ULTIMATE ANALYSIS				
C - % Dry	72.19	69.99	72.15	69.23
H - % Dry	5.05	4.81	5.09	4.93
S - % Dry	3.32	3.48	3.62	4.80
N - % Dry	1.38	1.33	1.43	1.33
Cl- % Dry	-	-	-	-
O - % Dry	8.69	6.94	8.47	8.43
Ash % Dry	9.37	13.45	9.24	11.28
BTU/ Lb.% Dry	13,060	12,602	12,974	12,374
ASH ELEMENTS				
SO_3	6.0	9.7	3.9	0.6
MgO	0.8	0.7	0.8	0.6
Na_2O	<0.1	<0.1	<0.1	<0.1
SiO_2	41.9	41.4	41.7	37.5
Al_2O_3	20.0	14.5	20.8	20.5
Fe_2O_3	24.8	24.6	27.7	40.6
CaO	5.9	8.4	3.4	0.7
K_2O	1.8	1.9	1.9	1.9
TiO_2	1.0	0.9	1.1	1.0
P_2O_5	<0.1	0.5	<0.1	<0.1
Total	102.2	102.6	101.3	103.4
ASH FUSION TEMPERATURES °F				
Reducing - ID	2020	2030	1980	2000
- H=W	2120	2070	2040	2040
- H=W/2	2270	2140	2280	2080
- Fluid	2340	2280	2330	2130
Oxidizing- ID	2360	2280	2400	2530
- H=W	2420	2350	2480	2570
- H=W/2	2540	2430	2530	2610
- Fluid	2580	2520	2580	2650

* Analyses furnished through the courtesy of Foster Wheeler Corporation.

APPENDIX B

TABLE 6

COAL AND PETROLEUM COKE ANALYSES

ALABAMA POWER COMPANY
BARRY STATION, BOILER NO. 4

Run No.	1		2		6		8		13		13A	
Laboratory No.	6076	6077	6078	6079	6080	6081	6082	6083	6084	6085	6086	6087
Sample Identification*	1-A,B,D,E	1-C	2-A,B,D,E	2-C	6-B,D,E	6-C	8-B,D,E	8-C	13-A,B,D,E	13-C	13-A,B,D,E	13-C
Sample Date	1-23-73	1-23	1-23	1-23	1-23	1023	1023	1023	1-19	1-19	2-5	2-5-73
Raw Coal Sample												
Proximate Analysis												
Moisture	7.72	6.40	6.99	5.69	7.25	5.76	6.09	6.33	8.17	8.13	2.10	8.09
Ash	12.11	2.22	11.86	2.37	10.89	1.93	9.95	2.79	12.76	13.14	10.03	9.71
Volatiles	31.73	14.67	32.12	14.76	32.40	14.82	33.23	14.59	31.29	31.16	34.78	32.53
Fixed Carbon	48.44	76.71	49.03	77.18	49.46	77.49	50.73	76.29	47.78	47.57	53.09	49.67
Btu/lb	11,877	14,020	12,022	14,106	12,127	14,163	12,438	13,943	11,714	11,664	13,017	12,178
Ultimate Analysis												
C - % Dry	71.39	85.11	71.69	84.99	72.52	85.39	73.47	84.58	70.76	70.42	73.75	73.49
H - % Dry	4.75	4.01	4.77	4.00	4.83	4.02	4.89	3.98	4.71	4.69	4.91	4.89
S - % Dry	2.73	3.97	2.65	3.98	2.61	4.03	2.68	3.81	2.40	1.92	3.38	3.15
N - % Dry	1.52	1.20	1.55	1.08	1.59	1.22	1.59	1.25	1.52	1.45	1.43	1.39
Cl - % Dry	0.09	0.0	--	--	--	--	--	--	--	--	--	--
O - % Dry	6.40	3.34	6.59	3.44	6.71	3.29	6.78	3.40	6.72	7.22	6.28	6.52
Ash - % Dry	13.12	2.37	12.75	2.51	11.74	2.05	10.59	2.98	13.89	14.30	10.25	10.56
% Used	80.2	19.8	80.3	19.7	75.6	24.4	75.8	24.2	81.4	18.6	77.7	22.3
Ash Elements												
P_2O_5	0.37	0.38										
SiO_2	45.62	45.91										
Fe_2O_3	19.01	16.93										
Al_2O_3	24.06	21.91										
TiO_2	1.10	1.08										
CuO	2.57	4.36										
MgO	0.89	1.09										
SO_3	3.31	4.28										
K_2O	2.09	2.04										
Na_2O	0.31	0.03										
Total	99.33	98.28										
Ash Fusion - Reducing												
I.D.	2100	--										
H=W	2135	--										
H=1/2W	2150	--										
Fluid	2180	--										
- Oxidizing												
I.D.	2485	--										
H=W	2525	--										
H=1/2W	2550	--										
Fluid	2560	--										

*** Note:**

- Letters refer to pulverizers.
- Samples marked "A, B, D, E" are 100% coal
- Samples marked "C" are petroleum coke or mixtures of coal and petroleum coke.

APPENDIX B

TABLE 6 (Continued)

COAL AND PETROLEUM COKE ANALYSES

ALABAMA POWER COMPANY
BARRY STATION, BOILER NO. 4

Run No.	20		29		30		31		42A		42B	
Laboratory No.	6097	6098	6099	6100	6101	6102	6103	6104	6106	6107	6108	6109
Sample Identification*	20-A,B,D,E	20-C	29-A,B,D,E	29-C	30-A,B,D,E	30-C	31-A,B,D,E	31-C	42A-B,D,E	42A-C	42B-B,D,E,	42B-C
Sample Date	1-22	1-22	1-19	1-19	1-19	1-19	1-19	1-19	2-22	2-22	2-23	2-23
Conditions	Base											
Raw Coal Sample												
Proximate Analysis												
Moisture	10.38	6.37	9.16	8.47	7.21	8.03	8.76	6.98	10.05	6.74	10.01	6.18
Ash	9.36	2.55	13.24	10.86	9.08	11.20	12.71	9.43	6.85	0.11	6.99	0.11
Volatiles	31.76	14.62	30.71	18.83	33.13	18.86	31.08	19.51	36.76	12.03	36.72	12.10
Fixed Carbon	48.50	76.46	46.89	61.84	50.58	61.91	47.45	64.08	46.34	81.12	46.28	81.61
Btu/lb	11,890	13,974	11,496	11,394	12,401	12,410	11,634	12,843	11,929	14,382	11,915	14,468
Ultimate Analysis												
C - % Dry	73.59	84.80	70.19	75.74	74.13	75.46	70.22	77.22	73.13	86.42	73.01	86.43
H - % Dry	4.90	4.00	4.67	4.47	4.93	4.45	4.71	4.55	5.22	3.86	5.21	3.86
S - % Dry	3.38	4.04	2.05	2.39	2.58	2.45	2.06	2.18	3.18	4.52	3.29	4.59
N - % Dry	1.50	1.19	1.51	1.47	1.30	1.51	1.49	1.34	1.44	1.13	1.38	1.14
Cl - % Dry	--	--	--	--	--	--	--	--	.061	--	--	--
O - % Dry	6.19	3.25	7.00	4.07	7.27	3.95	7.09	4.57	9.35	4.07	9.34	3.87
Ash - % Dry	10.44	2.72	14.58	11.86	9.79	12.18	13.93	10.14	7.62	0.12	7.77	.114
% Used	76.5	23.5	81.4	18.6	81.2	18.8	81.3	18.7	69.3	30.7	69.0	31.0
Ash Elements												
P_2O_5									.23	.39		
SiO_2									45.30	26.15		
Fe_2O_3									23.95	20.15		
Al_2O_3									22.58	14.29		
TiO_2									1.17	1.42		
CaO									1.50	3.69		
MgO									0.60	0.98		
SO_3									1.67	3.25		
K_2O									1.95	2.31		
Na_2O									0.14	0.49		
Total									99.09	73.18		
Ash Fusion - Reducing												
I.D.									2070	--		
H=W									2100	--		
H=1/2W									2120	--		
Fluid									2140	--		
- Oxidizing												
I.D.									2535	--		
H=W									2560	--		
H=1/2W									2570	--		
Fluid									2600	--		

* Note:

- Letters refer to pulverizers
- Samples marked "A, B, D, E" are 100% coal
- Samples marked "C" are petroleum coke or mixtures of coal and petroleum coke.

APPENDIX B

TABLE 6 (Continued)

COAL AND PETROLEUM COKE ANALYSES

ALABAMA POWER COMPANY
BARRY STATION, BOILER NO. 4

Run No.	17		18	19		19A		19B	
Laboratory No.	6088	6089	6090	6091	6092	6093	6094	6095	6096
Sample Identification*	17-A,B,D,E	17-C	18-B,D,E	19-B,D,E	19-C	19A-B,D,E	19A-C	19B-B,D,E	19B-C
Sample Date	1-22	1-22	1-22	1-22	1-22	2-13	2-13	2-14	2-14
Conditions						Low NO_x			
Proximate Analysis									
Moisture	10.33	6.42	10.58	8.42	6.40	8.05	9.42	9.84	6.93
Ash	10.17	2.47	8.17	9.41	2.42	11.33	9.21	7.67	11.51
Volatiles	31.46	14.63	32.16	32.52	14.64	33.37	19.00	34.14	19.04
Fixed Carbon	48.04	76.48	49.09	49.65	76.54	47.25	62.37	48.35	62.52
Btu/Lb	11,778	13,979	12,037	12,173	13,989	11,665	12,502	11,936	12,531
Ultimate Analysis									
C - % Dry	72.85	84.87	74.66	73.73	84.92	70.32	77.19	73.38	75.30
H - % Dry	4.85	4.00	4.97	4.91	4.00	4.88	4.55	5.09	4.44
S - % Dry	3.63	3.98	3.56	3.51	4.14	2.90	3.16	3.29	2.81
N - % Dry	1.48	1.20	1.52	1.50	1.17	1.40	1.32	1.44	1.41
Cl - % Dry	--	--	--	--	--	--	--	0.073	--
O - % Dry	5.85	3.31	6.15	6.08	3.18	8.18	3.61	8.23	3.67
Ash - % Dry	11.34	2.64	9.14	10.28	2.59	12.32	10.17	8.50	12.37
% Used	79.7	20.3	100.0	77.0	23	69.8	30.2	69.6	30.4
Ash Elements									
P_2O_5								0.40	.81
SiO_2								44.50	48.08
Fe_2O_3								22.21	13.85
Al_2O_3								22.49	27.47
TiO_2								1.17	1.45
CuO								1.99	2.00
								0.88	1.10
SO_3								2.17	2.09
K_2O								2.38	2.39
Na_2O								0.32	0.28
Total								98.50	99.52
Ash Fusion - Reducing									
I.D.								2050	--
H=W								2100	--
H=1/2W								2115	--
Fluid								2130	--
- Oxidizing									--
I.D.								2450	--
H=W								2500	--
H-1/2W								2525	--
Fluid								2535	--

* Note:

- Letters refer to pulverizers
- Samples marked "A, B, D, E" are 100% coal
- Samples marked "C" are petroleum coke or mixtures of coal and petroleum coke.

APPENDIX B

TABLE 7

COAL ANALYSES

TAMPA ELECTRIC CO.
BIG BEND STATION, BOILER NO. 2

Laboratory No.	96135	96136	96137	96138	96139
Run No.	4	2	3	10	20
Date	3-5-73	3-6-73	3-[illegible]-73	3-12-73	3-7-73
Time	1730	0930	1445	1230	0830
Proximate Analysis					
Moisture - %	10.63	11.66	10.75	10.85	10.98
Ash - %	13.13	14.07	13.78	13.52	13.85
Volatiles - %	34.16	32.60	34.54	33.88	33.68
Fixed C - %	42.08	42.21	40.93	41.75	41.75
Sulfur - %	3.48	3.19	3.44	3.66	3.72
BTU/lb - %	10,682	10,585	19,576	10,780	10,505
Ultimate Analysis					
C - % Dry	66.49	65.75	66.02	66.86	65.86
H - % Dry	4.71	4.65	4.59	4.71	4.56
S - % Dry	3.89	3.61	3.86	4.11	4.18
N - % Dry	1.26	1.39	1.41	1.39	1.38
Cl - % Dry	.03	0.10	0.10	-----	-----
O - % Dry	8.96	9.21	8.68	7.77	8.47
Ash - % Dry	14.69	15.93	15.44	15.16	15.55
BTU/lb - % Dry	11,952	11,982	11,849	12,092	11,801
Ash Elements					
P_2O_5		0.31	0.26		
SiO_2		44.86	45.21		
Fe_2O_3		22.90	20.28		
Al_2O_3		17.83	17.66		
TiO_2		.80	0.87		
CaO		4.87	4.91		
MgO		0.86	0.83		
SO_3		6.16	6.85		
K_2O		2.11	2.00		
Na_2O		0.21	0.22		
Total		100.89	99.10		
Ash Fusion Temperatures °F					
Reducing - I.D.		2000	2000		
- H=W		2015	2040		
- H=W/2		2035	2050		
- Fluid		2045	2075		
Oxidizing - I.D.		2340	2320		
- H=W		2370	2380		
- H=W/2		2450	2450		
- Fluid		2475	2470		

APPENDIX B

TABLE 8

COAL ANALYSES

CENTRAL ILLINOIS LIGHT COMPANY
E. D. EDWARDS STATION, BOILER NO. 2

Laboratory No.		96168	96169	96170	96171	96172	96173	96174	96175	96176	96177
Run No.		1	2	3	4	5	6	7	8	23	24
Mills		ABCD	ABCD	ABCD	ABCD	ABCD	ABCD	ABC	ABC	ABCD	ABCD
Date		6-11-73	6-11-73	6-12-73	6-12-73	6-12-73	6-12-73	6-13-73	6-13-73	6-13-73	6-13-73
Proximate Analysis											
Moisture		15.97	15.65	16.77	16.02	17.07	17.26	17.40	18.07	15.94	16.04
Ash		9.94	9.38	9.83	9.34	10.61	14.07	9.68	9.53	9.33	8.89
Volatiles		32.81	33.20	32.50	31.91	32.02	30.41	32.29	32.06	33.28	33.24
Fixed Carbon		41.28	41.77	40.90	42.73	40.29	38.26	40.63	40.34	46.45	41.83
Sulfur		3.07	2.90	2.94	3.00	2.66	2.56	2.69	2.80	2.88	2.98
BTU/LB.		10,433	10,557	10,335	10,530	10,183	10,170	10,268	10,195	10,576	10,571
Hardgrove Grind.					54.5					54.5	
Ultimate Analysis											
C	- % Dry	68.96	69.51	68.97	69.66	68.21	64.91	69.04	69.11	69.851	69.93
H	- % Dry	4.96	5.00	4.97	4.99	4.91	4.67	4.97	4.98	4.993	5.03
S	- % Dry	3.66	3.44	3.53	3.57	3.21	3.09	3.26	3.41	3.429	3.55
N	- % Dry	1.25	1.27	1.25	1.26	1.20	1.19	1.24	1.25	1.236	1.25
Cl	- % Dry	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.022	0.02
O	- % Dry	9.32	9.64	9.45	9.38	9.66	9.11	9.75	9.60	9.37	9.63
Ash	- % Dry	11.829	11.12	11.81	11.12	12.79	17.01	11.72	11.63	11.10	10.59
BTU/LB.	- % Dry	12,416	12,516	12,417	12,539	12,279	12,292	12,431	12,444	12,582	12,591

Laboratory No.		96178	96179	96180	96181	96182	96183	96184	96185	96186	96187
Run No.		13	18	14	10	11	12	9	16	20	1A
Mills		ABC	ABC	ABC	ABC	ABC	ABC	ABC	ABCD	ABC	ABCD
Date		6-13-73	6-13-73	6-14-73	6-14-73	6-14-73	6-14-73	6-14-73	6-15-73	6-15-73	6-15-73
Proximate Analysis											
Moisture		17.37	17.65	17.12	16.55	16.29	15.40	15.37	14.89	15.27	13.72
Ash		9.27	8.66	9.90	9.22	9.55	9.59	9.37	9.17	9.29	8.24
Volatiles		32.48	32.63	32.32	32.87	32.84	34.17	33.33	33.63	33.40	34.56
Fixed Carbon		40.88	41.06	40.66	41.36	41.32	40.84	41.93	42.32	42.04	43.48
Sulfur		2.80	2.46	2.80	2.82	2.91	3.10	2.93	30.1	3.05	1.97
BTU/LB.		10,330	10,376	10,276	19,452	10,442	10,488	10,597	10,695	10,623	10,989
Hardgrove Grind.							55.9				
Ultimate Analysis											
C	- % Dry	69.43	69.98	68.87	69.57	69.29	68.86	69.55	69.79	69.64	70.78
H	- % Dry	5.00	5.04	4.96	5.01	4.99	5.01	5.01	5.02	5.01	5.10
S	- % Dry	3.39	2.99	3.37	3.38	3.47	3.66	3.47	3.53	3.60	2.29
N	- % Dry	1.24	1.25	1.18	1.26	1.26	1.32	1.28	1.23	1.23	1.42
Cl	- % Dry	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.02	0.02	0.02
O	- % Dry	9.70	10.20	9.66	9.71	9.56	9.78	9.60	9.64	9.54	10.89
Ash	- % Dry	11.22	10.52	11.94	11.05	11.41	11.34	11.07	10.77	10.96	9.50
BTU/LB.	- % Dry	12,502	12,600	12,399	12,525	12,474	12,397	12,522	12,565	12,537	12,670

APPENDIX B

TABLE 9

COAL ANALYSES

BASIN ELECTRIC POWER COOPERATIVE
STANTON, NORTH DAKOTA, BOILER NO. 1

	Base		Low NO_x							
Laboratory No.	96189	96190	96191	96192	96193	96194	96195	96916	96197	96198
Run No.	1	1A	3 & 4	4A & B	4C	5	6	7	9	11
Source	Storage	Mine	Storage	--	Mine	Storage	Mine	Mine	Mine	Mine
Date	7/6/73	7/10/73	7/9/73	7/11/73	7/12/73	7/9/73	7/10/73	7/10/73	7/10/73	7/10/73
Proximate Analysis										
Moisture	36.44	38.71	34.42	38.36	37.59	36.94	37.95	39.21	38.11	37.66
Ash	7.61	5.90	6.16	5.55	6.30	5.29	6.03	5.92	8.54	6.11
Volatiles	28.01	27.02	29.75	29.19	27.72	28.93	28.05	27.47	26.71	28.15
Fixed Carbon	27.70	28.36	29.41	26.91	28.39	28.60	27.73	27.16	26.41	27.83
Sulfur	0.41	0.53	0.43	0.46	0.34	0.35	0.43	0.38	1.11	0.46
Btu/Lb	6704	6643	7120	6710	6728	6922	6712	6575	6392	6737
Hardgrove Grind.		29.5		27.3	27.3					
Ultimate Analysis										
C - % Dry	62.81	64.44	64.66	65.03	64.11	65.37	64.42	64.42	61.51	64.36
H - % Dry	4.27	4.43	4.39	4.39	4.35	4.44	4.38	4.38	4.18	4.37
S - % Dry	0.64	0.87	0.66	0.47	0.55	0.55	0.69	0.62	1.37	0.74
N - % Dry	1.04	1.08	1.03	1.09	1.12	1.08	1.05	1.05	1.11	1.07
Cl - % Dry	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
O - % Dry	19.17	19.55	19.73	19.76	19.78	19.95	19.66	19.66	18.77	19.64
Ash - % Dry	11.97	9.63	9.39	9.00	10.09	8.39	9.72	9.73	13.80	9.81
Btu/Lb - Dry	10548	10838	10858	10886	10781	10977	10817	10816	10328	10807
Ash Elements										
P_2O_5		0.08		0.06	0.07					
SiO_2		23.81		20.79	28.63					
Fe_2O_3		9.72		9.32	8.17					
Al_2O_3		9.69		9.13	10.07					
TiO_2		0.51		0.47	0.52					
CaO		19.00		20.44	18.70					
MgO		4.10		4.69	4.40					
SO_3		22.35		23.58	21.10					
K_2O		0.68		0.48	0.74					
Na_2O		7.90		7.68	5.20					
Total		97.83		96.63	97.61					
Ash Fusion Temperatures										
Reducing - I.D.		2220		1990	2090					
- H=W		2230		2120	2140					
- H=W/2		2240		2150	2145					
- Fluid		2250		2240	2150					
Oxidizing - I.D.		2250		2200	2190					
- H=W		2270		2275	2210					
- H=W/2		2275		2280	2220					
- Fluid		2280		2290	2225					

APPENDIX B

TABLE 10

COAL ANALYSES

PACIFIC POWER AND LIGHT CO, GLEN ROCK, WYOMING

DAVE JOHNSTON STATION

Laboratory No.	96203	96204	96205	96206	96207	96208	96209	96210	96211	96212	96213	96214	96215
Run No.	3	4	1	2	5	6	7	8	10	13	16	2	4
Boiler No.	2	2	2	2	2	2	2	2	2	2	2	4	4
Date	7/27/73	7/27/72	7/30/73	7/30/73	7/30/73	7/30/73	7/31/73	7/31/73	7/31/73	8/1/73	8/1/73	8/8/73	8/8/73
Proximate Analysis													
Moisture	26.05	27.25	28.86	28.27	28.21	28.26	28.58	28.85	29.31	29.28	27.54	16.51	15.32
Ash	13.80	11.31	7.55	7.07	7.71	7.63	7.77	7.31	7.22	6.43	7.58	13.67	16.29
Volatiles	30.67	31.33	32.42	32.97	32.67	32.69	32.46	32.55	32.36	32.78	33.08	35.55	34.82
Fixed Carbon	29.48	30.11	31.17	31.69	31.41	31.42	31.19	31.29	31.11	31.51	31.8C	34.26	33.56
Sulfur	0.51	0.55	0.45	0.46	0.48	0.53	0.46	0.49	0.56	0.49	0.56	0.63	0.57
Btu/Lb	7334	7491	7754	7884	7813	7817	7761	7784	7739	7839	7911	8464	8291
Hardgrove Grind.				28.7									
Ultimate Analysis													
C - % Dry	58.41	60.65	64.19	64.73	64.01	64.17	64.00	64.44	64.47	65.28	64.30	59.36	57.33
H - % Dry	4.23	4.39	4.65	4.69	4.64	4.65	4.63	4.67	4.67	4.73	4.66	4.33	4.18
S - % Dry	0.69	0.76	0.63	0.64	0.66	0.74	0.64	0.69	0.79	0.69	0.77	0.75	0.68
N - % Dry	0.77	0.79	0.83	0.82	0.82	0.86	0.83	0.81	0.83	0.81	0.84	0.75	0.76
Cl - % Dry	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.05
O - % Dry	17.38	18.05	19.10	19.26	19.07	19.10	19.04	19.18	19.19	19.43	19.13	18.44	17.81
Ash - % Dry	18.66	15.54	10.61	9.86	10.74	10.64	10.88	10.27	10.22	9.09	10.46	16.38	19.24
Btu/Lb - % Dry	9918	10298	10899	10991	10883	10896	10866	10941	10947	11085	10918	10138	9791
Ash Elements													
P_2O_5				0.54								0.31	
SiO_2				30.56								42.91	
Fe_2O_3				4.99								4.24	
Al_2O_3				15.21								18.77	
TiO				1.11								0.97	
CaO				26.12								15.67	
MgO				3.29								2.48	
SO_3				12.37								10.01	
K_2O				0.49								1.09	
Na_2O				0.55								0.47	
Total				95.24								96.93	
Ash Fusion Temperatures													
Reducing - I.D.				2125								2190	
- H=W				2145								2250	
- H=W/2				2150								2270	
- Fluid				2155								2300	
Oxidizing - I.D.				2170								2335	
- H=W				2190								2375	
- H=W/2				2200								2380	
- Fluid				2210								2390	

APPENDIX C

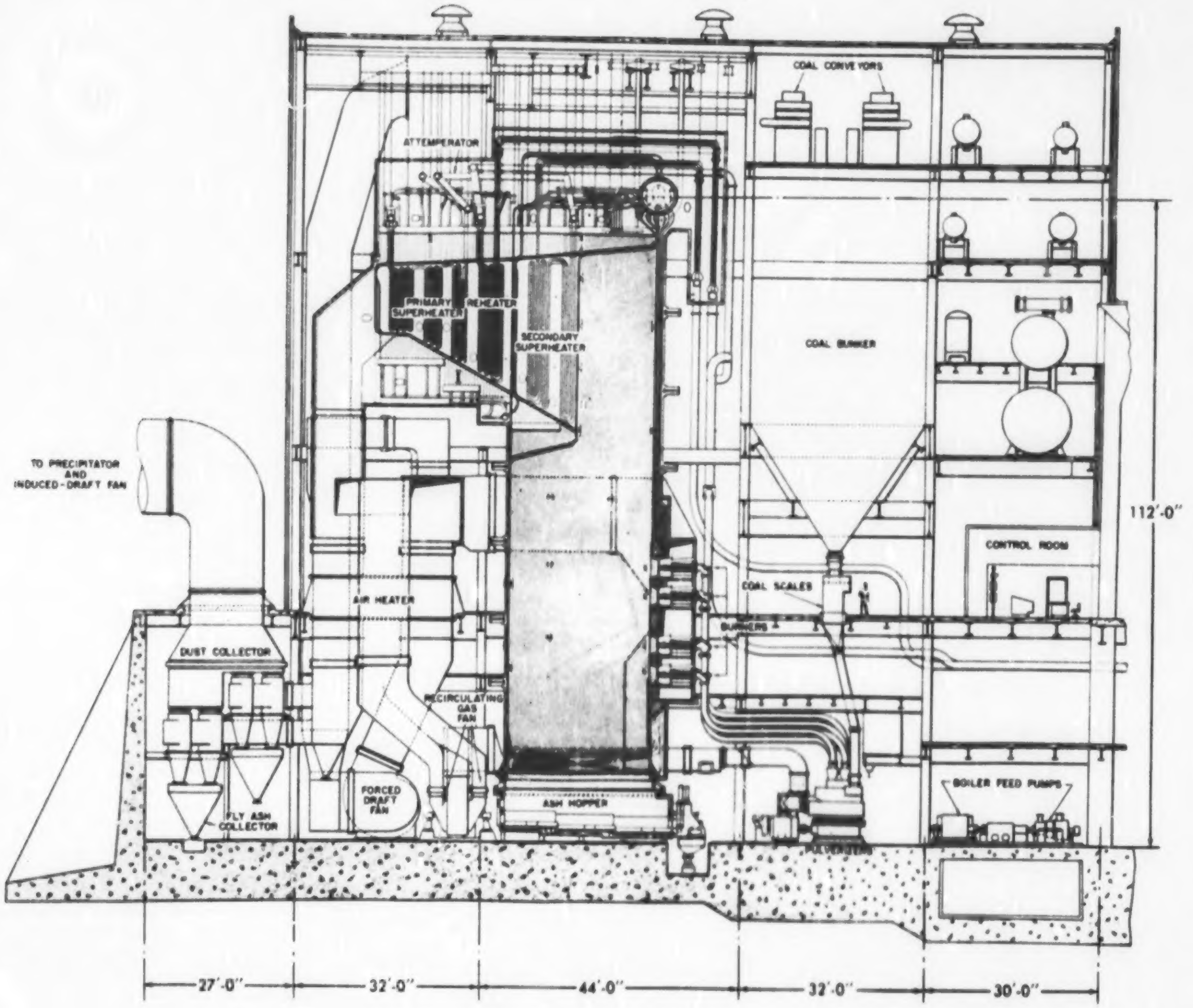
CROSS SECTION DRAWINGS OF TYPICAL UTILITY BOILERS

Typical utility boiler designs representative of the types of boilers tested in this program are shown in the cross sectional drawings in Figures 1 through 6 of Appendix C. Typical front wall and horizontally opposed fired boilers are shown in Figures 1, 2 and 3, respectively, a tangentially fired boiler is shown in Figure 4, and Figures 5 and 6 are typical of turbo furnace and cyclone fired units.

APPENDIX C

FIGURE 1

TYPICAL FRONT WALL FIRED BOILER

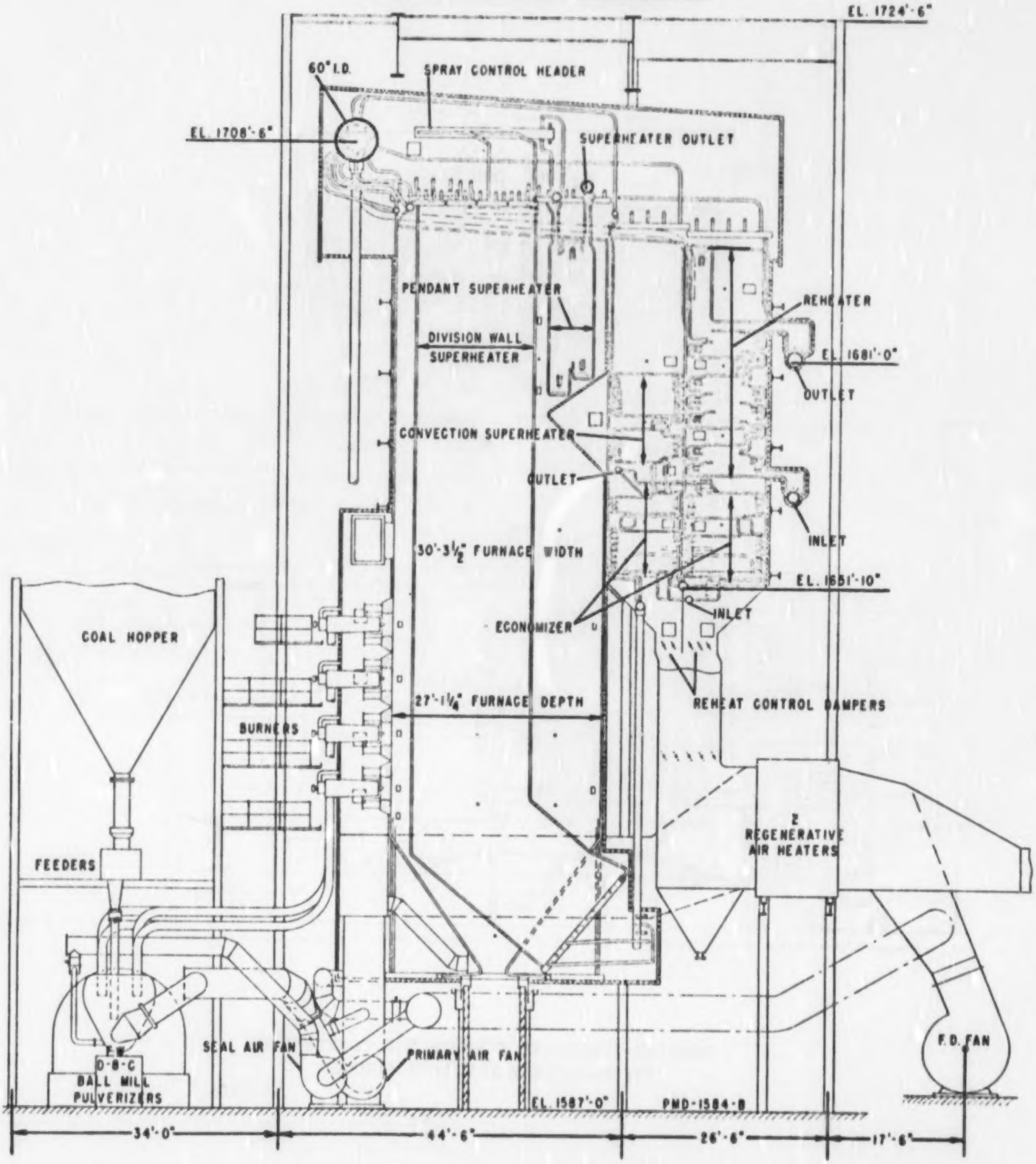

COAL CONVEYORS
ATTEMPERATOR
PRIMARY SUPERHEATER
REHEATER
SECONDARY SUPERHEATER
COAL BUNKER
TO PRECIPITATOR AND INDUCED-DRAFT FAN
112'-0"
CONTROL ROOM
COAL SCALES
AIR HEATER
BURNERS
DUST COLLECTOR
RECIRCULATING GAS FAN
BOILER FEED PUMPS
FORCED DRAFT FAN
ASH HOPPER
FLY ASH COLLECTOR
PULVERIZERS
27'-0"
32'-0"
44'-0"
32'-0"
30'-0"

DRAWING FURNISHED THROUGH THE COURTESY OF
THE BABCOCK AND WILCOX COMPANY

APPENDIX C

FIGURE 2

TYPICAL FRONT WALL FIRED BOILER

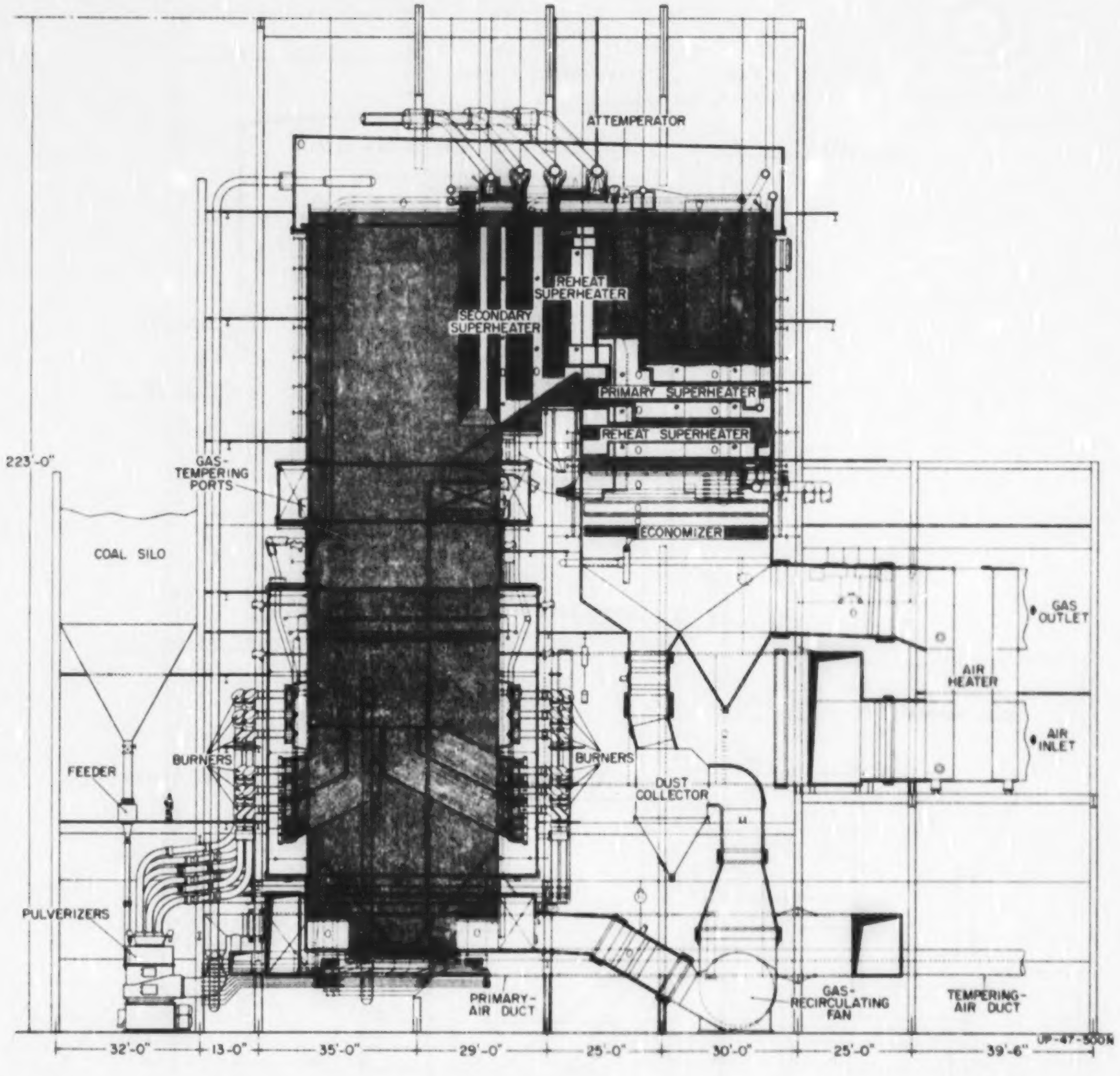

EL. 1724'-6"
60" I.D.
SPRAY CONTROL HEADER
EL. 1708'-6"
SUPERHEATER OUTLET
PENDANT SUPERHEATER
REHEATER
DIVISION WALL SUPERHEATER
EL. 1681'-0"
OUTLET
CONVECTION SUPERHEATER
OUTLET
INLET
30'-3½" FURNACE WIDTH
EL. 1651'-10"
INLET
COAL HOPPER
ECONOMIZER
REHEAT CONTROL DAMPERS
27'-1¼" FURNACE DEPTH
BURNERS
2 REGENERATIVE AIR HEATERS
FEEDERS
F.D. FAN
SEAL AIR FAN
PRIMARY AIR FAN
F-W D-8-C BALL MILL PULVERIZERS
EL. 1587'-0"
PMD-1584-B
34'-0"
44'-6"
26'-6"
17'-6"

DRAWING FURNISHED THROUGH THE COURTESY OF THE FOSTER WHEELER CORPORATION

APPENDIX C

FIGURE 3

TYPICAL HORIZONTALLY OPPOSED FIRED BOILER

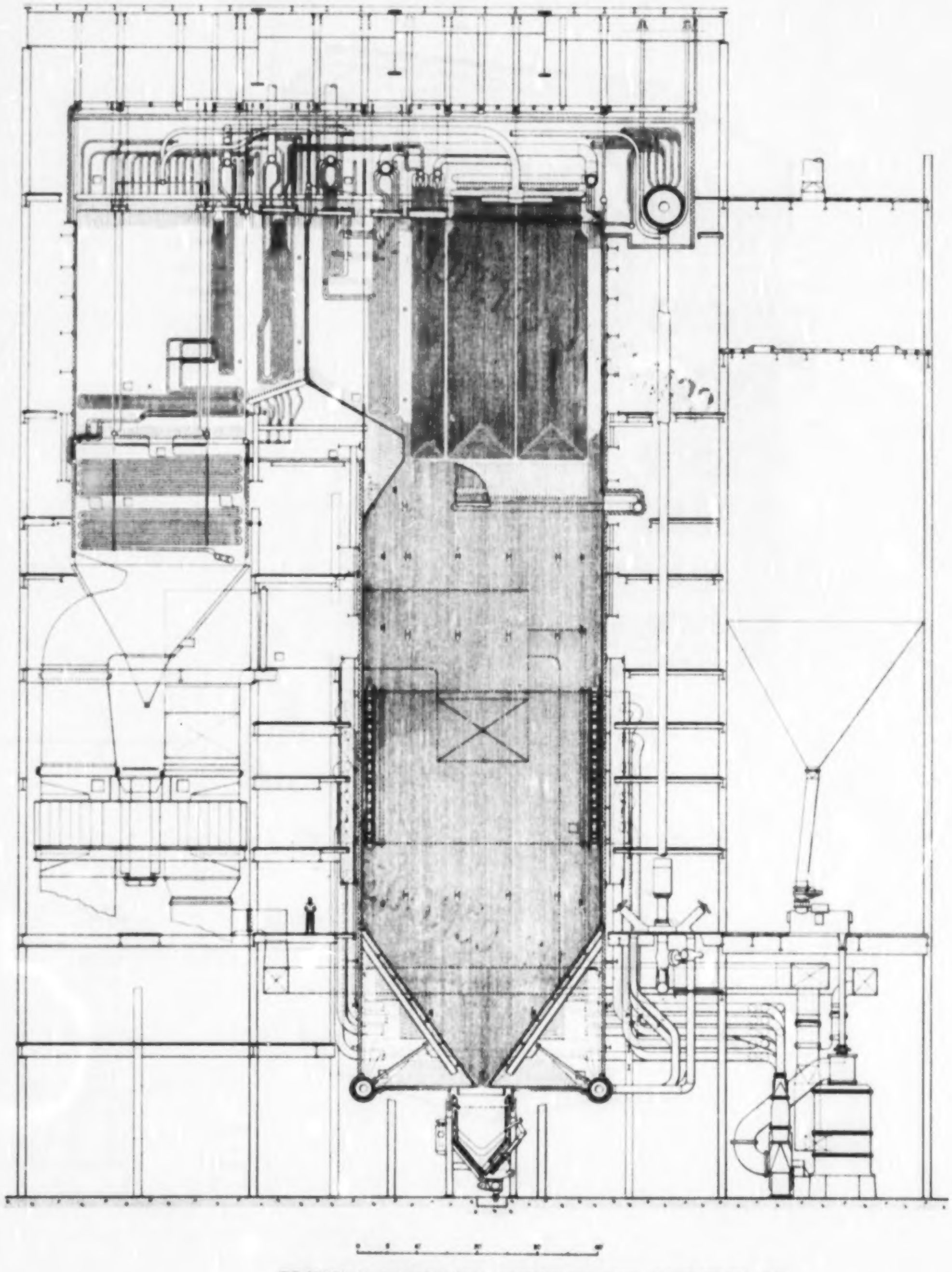

ATTEMPERATOR
REHEAT SUPERHEATER
SECONDARY SUPERHEATER
PRIMARY SUPERHEATER
REHEAT SUPERHEATER
223'-0"
GAS-TEMPERING PORTS
ECONOMIZER
COAL SILO
GAS OUTLET
AIR HEATER
AIR INLET
BURNERS
BURNERS
FEEDER
DUST COLLECTOR
PULVERIZERS
PRIMARY-AIR DUCT
GAS-RECIRCULATING FAN
TEMPERING-AIR DUCT
UP-47-500N
32'-0"
13'-0"
35'-0"
29'-0"
25'-0"
30'-0"
25'-0"
39'-6"

DRAWING FURNISHED THROUGH THE COURTESY OF
THE BABCOCK AND WILCOX COMPANY

APPENDIX C

FIGURE 4

TYPICAL TANGENTIALLY FIRED BOILER

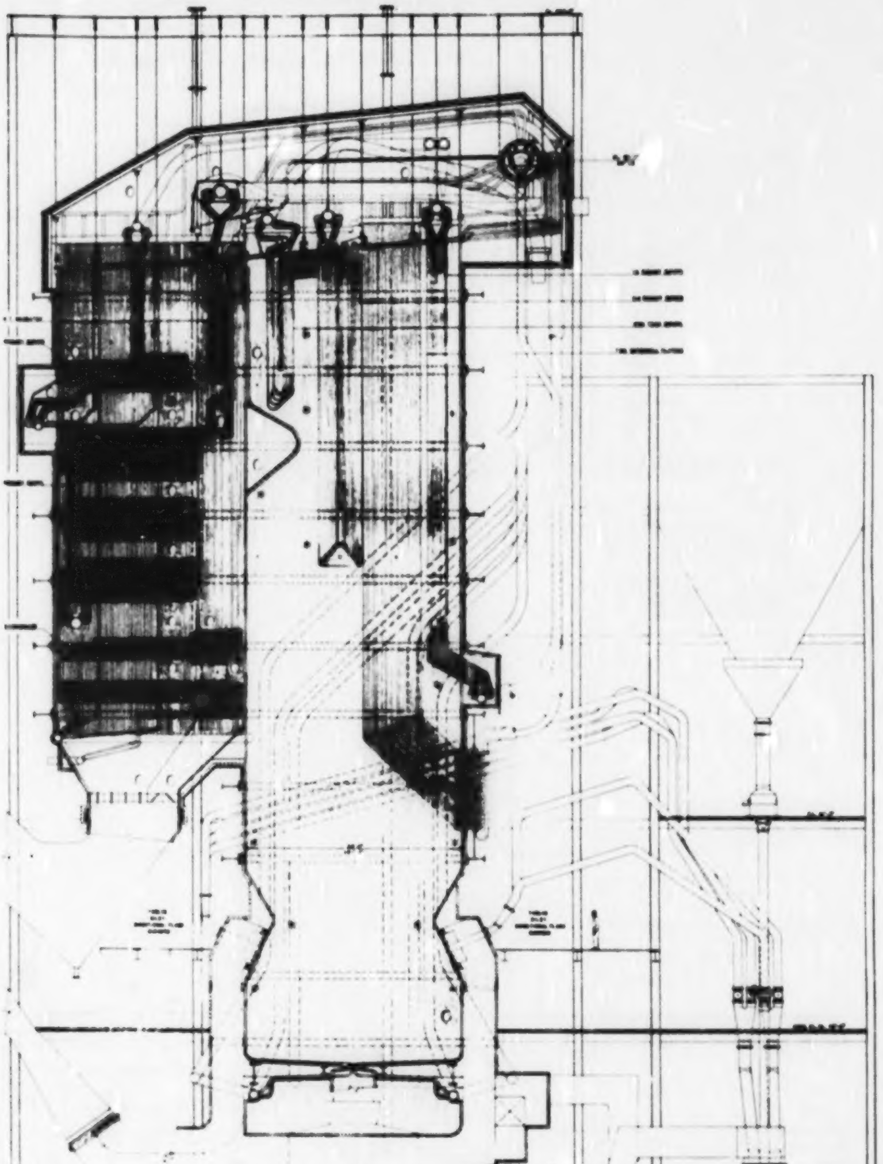


DRAWING FURNISHED THROUGH THE COURTESY OF
COMBUSTION ENGINEERING, INC.

APPENDIX C

FIGURE 5

TYPICAL TURBO FURNACE FIRED BOILER

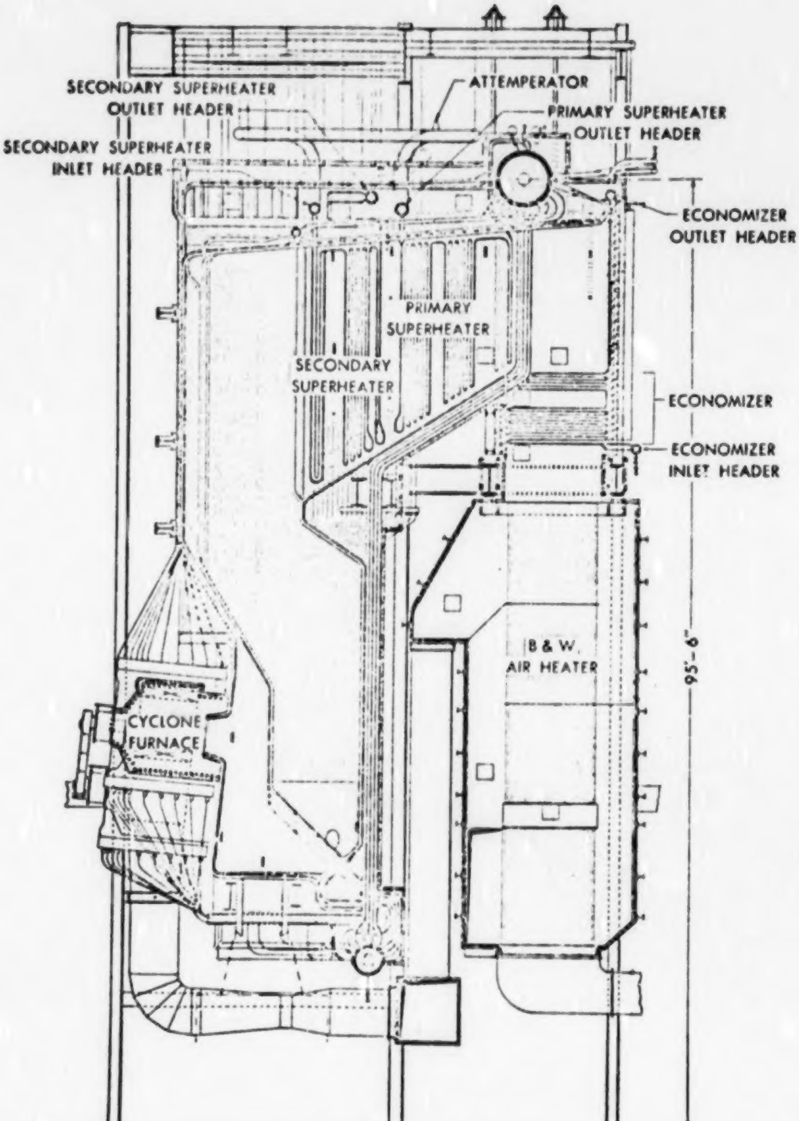


DRAWING FURNISHED THROUGH THE COURTESY
OF THE RILEY STOKER CORPORATION

APPENDIX C

FIGURE 6

TYPICAL CYCLONE FIRED BOILER


ATTEMPERATOR
SECONDARY SUPERHEATER OUTLET HEADER
PRIMARY SUPERHEATER OUTLET HEADER
SECONDARY SUPERHEATER INLET HEADER
ECONOMIZER OUTLET HEADER
PRIMARY SUPERHEATER
SECONDARY SUPERHEATER
ECONOMIZER
ECONOMIZER INLET HEADER
B & W. AIR HEATER
95'-6"
CYCLONE FURNACE
28'-6"
22'-0"

DRAWING FURNISHED THROUGH THE COURTESY
OF THE BABCOCK & WILCOX COMPANY

APPENDIX D

COMMENTS FROM BOILER MANUFACTURERS

At the request of the EPA Project Officer, the boiler manufacturers have reviewed this report. Written comments were received from Foster Wheeler Corporation and Riley Stoker Corporation which are included in Appendix D. These comments, plus verbal comments received from the Babcock and Wilcox Company, have been taken into account in revising the Final Report. Combustion Engineering, Inc. accepted the report as written.

The Riley Stoker Corporation in their comments, item 2, suggest that the correlation of NO_x emissions against megawatts per equivalent furnace firing wall should be changed to NO_x emissions versus boiler load in pounds of steam per hour. This is a valid comment but the suggested adjustment is within the limits of error of the current relationship. More data is needed in order to add this refinement. Riley also points out that the correlation does not take into account differences in fuel nitrogen content in the fuels fired. The authors agree that fuel nitrogen content is important. However, the factors influencing the quantitative conversion of fuel nitrogen to NO_x emissions in coal fired utility boilers have not yet been established. Therefore, a correlation of NO_x emissions with fuel nitrogen content is not yet possible. As more data are developed, the refinements in the correlations, as pointed out by Riley Stoker Corporation to be desirable, will be possible.

The authors of the report wish to thank the reviewers for their very constructive comments.

APPENDIX D

COMMENTS
TO
FINAL REPORT
FOR
EPA CONTRACT NO. 68-02-02227

FIELD TESTING: APPLICATION OF COMBUSTION MODIFICATIONS TO CONTROL NO_x EMISSIONS FOR LARGE UTILITY BOILERS

FOSTER WHEELER CORPORATION
110 SOUTH ORANGE AVENUE, LIVINGSTON, N. J.

Prepared by:

R. E. Sommerlad, Manager
Development Contract Operations Dept.
Research Division

INTRODUCTION

Foster Wheeler Corporation and its client, Gulf Power Company, were pleased to participate with the Environmental Protection Agency and its contractor, Esso Research and Engineering Company, in a program entitled "Field Testing: Application of Combustion Modifications to Control NO_x Emissions for Large Utility Boilers". The purpose of this appendix is to relate the efforts by the various participants in this program and to correlate the results found with similar test programs by Foster Wheeler.

TEST PROGRAM

The program was conducted as described in Sections 4.1.1-4.1.3 and 6.1.1.1.4 of the report and included an agreement among the participants. The test program included specific tests requested by FW as well as those requested by ERE. New test connections were installed by Gulf. ERE and FW test crews arrived in early December and data were taken through Dec. 14, 1972. Due to anticipated load demands and ERE vacation schedules the test crews re-assembled in January 1973 to renew testing. During the interim period FW Service Engineers re-aligned registers and pulverizers to attempt to correct side-to-side unbalances as indicated by the flue gas composition. The January period also proved fruitless due to operating demands. All parties had previously agreed that load demand would have the highest priority. As might be expected this period of time coincided with unseasonable cold weather requiring peak power almost constantly. In order to keep other commitments ERE had to go on to other plants. ERE returned in March for two days. FW resident service staff assisted but FW test crews had been committed to other assignments.

PERFORMANCE TESTS

In addition to the resident start-up crew FW provided a performance test crew comprising five engineers and the district service manager. Complete performance test data were obtained for five runs and included, complete control data*, tube metal temperatures, fan and pulverizer power input*, local steam and water pressures and temperatures, local air and gas temperatures and pressures*, atmospheric ambient conditions, flue gas composition from an array of multiple points, air register and damper positions*, ash coverage diagrams, and coal, bottom ash and fly ash samples for chemical analyses. Partial sets of data* were obtained during the eight runs. Two runs were attempted but then aborted due to lack of stabilization time. FW was concerned the firing unbalance from side-to-side which was evident by local O_2, NO_x and CO data as measured. This concern was later shown by chemical analyses of bottom ash and fly ash which averaged 10.8 and 24.8% combustible.

As mentioned previously FW spent considerable time adjusting firing equipment in late December with the hope that the December tests could be repeated with more meaningful results. FW had run performance tests previously on this unit and NO_x tests on an identical unit and therefore could anticipate the results. Unfortunately the results of these endeavors were not realized in January. During ERE's tests in March the results of the above endeavors were apparent by the consistency of O_2 readings by ERE as shown in Table 4, Appendix A. However, the NO_x data appear to confirm a

*Partial set includes items from complete set marked with asterisks.

suspicion FW had formulated during the December tests as described below.

GASEOUS EMISSION TESTS

In addition to the FW test crews mentioned earlier, FW also provided an emission test crew comprising five engineers and technicians. This included FW's Mobile Pollution Monitoring Laboratory which housed continuous analyzers for O_2, NO_x, and SO_2. FW also brought in a trailer, the apparatus to conduct wet chemical analyses and specified by EPA in the Test Methods for the Standards of Performance. FW probes were installed alongside ERE probes. The results of these efforts indicated that emission measuring by FW's continuous analyzers were the same as ERE's analyzers and in addition were confirmed by the EPA wet chemical procedures. Members of the emission test crew also aided ERE in particulate testing.

DISCUSSION OF RESULTS

As indicated previously FW has hopes of participating in this program to achieve meaningful results during the short test-period runs as had been achieved by FW on an identical unit. For this reason both performance and emission test crews were committed to this test program. It was also anticipated that FW would oversee the 1-3 day sustained "low NO_x" run and the 300-hr sustained "low NO_x" and normal operation runs. Due to the unexpected results of the short test-period and the unavailability of the unit for re-testing, FW felt the performance test results were not indicative of good commercial operation and declined to submit same in detail.

On an identical unit FW data were the same as the ERE data for "Low NO_x I", S_3 (Burners 2 & 3 on Air only). However for "Low NO_x II, S_4 (Burners 1, 2, 3 & 4 on Air only) and S_6 (Burners 5, 6, 7 & 8 on Air only) the NO_x

reduction as % Baseline (20% Excess Air) NO_x was 33.3 where the % Stoichiometric Air to Active Burners calculated by FW was 88.0 which is in agreement with ERE's analysis as shown in Figure 2-4.

During the December tests there was some confusion about register settings and rotation on three of the burners on the "A" side (Burner No. 3, 4 and 7). Prior to the test program these burner-register assemblies had been damaged and had been replaced with three assemblies from Unit No. 7 under construction at the time. The new assemblies were similar to the old assemblies and were fitted quite easily. However, the new assemblies had a reversible register assembly. To reverse the assembly is normally a shop setting. These registers had to be rotated in the field requiring that the motor drives be reversed, hence the confusion. Morever, the number of register blades and the shape of each individual blade is different. Even though all assemblies were realigned in late December 1972 resulting in a better side-to-side O_2 balance as observed by ERE in March 1973, it is felt that the individual air flow rate and possibly the flow characteristics of the new assembly are different than the old assembly and effect swirl and firing characteristics. It is felt by some that the NO_x formation occurs within 1 or 2 feet of the throat and this could serve to explain the high NO_x on the "A" side.

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WORCESTER, MASSACHUSETTS 01613

STEAM GENERATING
AND FUEL BURNING
EQUIPMENT

"Field Testing - Application of Combustion Modifications to Control NO_x Emissions from Large Utility Boilers" by W. Bartok, A.R. Crawford, E.H. Manny, L. Berkowitz, and R.E. Hall

Review:

Speaking for those of us at Riley who had the privilege of working with the Esso "Tigers" test crew during the planning and execution of their test program, the writer is pleased to have the opportunity to commend these people for their excellent work. The subject report illuminates Esso's experience in reducing nitrogen oxides (NO_x) emissions from coal fired utility boilers.

Our comments and criticisms of this report are few. It is perhaps the most accurate and fully documented study of two-staged combustion yet to be published. It was gratifying to us that the results of this study corroborate the results of our own test program which investigated the two-staged combustion of coal. We also found that there is a direct relationship between the air/fuel ratio at the fuel-rich burners and the reduction of NO_x emissions from all utility boilers. Our own data, when plotted against % of stoichiometric air to active burners, fit right on top of the data in Figure 2-4 of this report. We also liked the way Esso addressed iteslf to the potential operating problems involved with combustion modification. Their corrosion probe results, although not conclusive, do indicate that the tube wastage during two-staged combustion may be an overrated fear.

The following are our criticisms of the report:

1. On page 99, where the report describes the test conditions at Tampa Electric's Big Bend No. 2 unit, we would like to make a few clarifications. At the time of the test, the unit was limited to 375 M W due to superheater slagging (from an isolated shipment of troublesome coal) and a steam temperature problem which has been corrected after an extensive research program. This unit has been running for quite some time at a load of 3,000,000 lb/HR of steam (after all, a boiler produces steam, not megawatts) which is above the maximum continuous rating of 2,856,000 lb/HR. However, the unit still has not exceeded 410-420 M W at this steam flow due to problems inherent in the turbine.

2. The above point brings up one of the weaknesses of Esso's method of correlating NO_x emissions with the quantity "M W per equivalent furnace firing wall." This correlation does not consider the efficiency of the turbine which is completely unrelated to boiler operation. Thus units such as Big Bend 2, whose turbines are less efficient, are unduly penalized in the correlation.

The other main weakness of the correlation is the fact that differences in fuel nitrogen content are ignored. In this study, the chemically bound nitrogen ranged from 0.75% at Leland Olds to 1.93% at Harllee Branch. Certainly, M W per firing wall, which is proportional to bulk flame temperature, does not reflect fuel nitrogen conversion which has been shown to be essentially independent of temperature. We would suggest a correlation based on steam flow or heat input per firing wall, with a correction factor to "normalize" the data to a common fuel nitrogen content (say, 1.3%).

3. On page 65, the report indicates that closing the air registers to the fuel-rich burners maximized NO_x reductions because the minimum allowable excess air was reduced. We feel that it is just as important to note that in addition, a lower % of stoichiometric air is introduced to the fuel rich burners when the air registers are pinched to 20-30% open because the flow restriction upsets the balance of air flow to each burner. Therefore a boiler operating at a .9 stoichiometric ratio with all registers at 50% open may actually reach a .85 stoichiometric ratio when the registers are closed to 20% open.

4. In several instances the report states that baseline NO_x emissions level out at low loads because a larger percentage of the total NO_x is produced from the fuel nitrogen. This is certainly true, but no mention is made of the amount of excess air, which may double at low loads. Increased oxygen in the flame increases both thermal NO_x formation and fuel nitrogen conversion in diffusion flames (in premixed flames, thermal NO_x decreases with high excess air due to overall cooling of the flame). In cases where fuel NO_x is dominant at low loads, we have observed total NO_x emissions to increase as load decreases.

In conclusion, we are glad to see that this final report does not mark the end of Esso's involvement with EPA and NO_x testing. There certainly is much more to learn by extended operation of utility boilers under low NO_x conditions. Such a program as outlined in section 7 of this report would greatly benefit the utilities, the boiler manufacturers, and, most of all, the environment.

A. H. Rawdon - Director of R & D
S.A. Johnson - Chemical Research
Engineer
Riley Stoker Corporation

APPENDIX E

CONVERSION FACTORS

ENGLISH TO METRIC UNITS

To Convert From	To	Multiply By
Btu	Calories, kg	0.25198
Btu/pound	Calories, kg/kilogram	0.55552
Cubic feet/day	Cubic meters/day	0.028317
Feet	Meters	0.30480
Gallons/minute	Cubic meters/minute	0.0037854
Inches	Centimeters	2.5400
Pounds	Kilograms	0.45359
Pounds/Btu	Kilograms/calorie, kg	1.8001
Btu/Pound	Kcal/Kg	0.555
Pounds/hour	Kilograms/hour	0.45359
Pounds/square inch	Kilograms/square centimeter	0.070307
Tons	Metric tons	0.90719
Tons/Day	Metric tons/day	0.90719